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November 15,2002

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VIA HAND DELIVERY

Mr. Thomas Dorman
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, Kentucky 40602

Re: PSC Case No. 2002-00377

Dear Mr. Dorman:

Enclosed for filing are the original and ten copies of the Kentucky Power Company d/b/a American Electric Power's Integrated Resource Planning Report submitted pursuant to Commission Regulation 807 KAR 5:058.

If you have any questions please do not hesitate to call.

Very truly yours,

STITES & HARBISON, PLLC

Judith A. Villines

Judith A. Villines

JAV:las
Enclosures

cc: Elizabeth E. Blacltford
Michael L. Kurtz
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Errol K. Wagner

KE057:KE113:8282:FRANKFORT

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KENTUCKY BOWER COMPANY

INTEGRATED RESOURCE PLANNING REPORT
TO THE
KENTUCKY PUBLIC SERVICE COMMISSION

Submitted Pursuant to
Commission Regulation 807 KAR 5:058

Case No. 2002-00377
November 15,2002

KENTUCKY POWER COMPANY

INTEGRATED RESOURCE PLANNING REPORT
TO THE
KENTUCKY PUBLIC SERVICE COMMISSION

Submitted Pursuant to
Commission Regulation 807 KAR 5:058

Case No. 2002-00377
November 15,2002

This report was prepared under the supervision of :

Errol K. Wagner
Kentucky Power Company d/b/a American Electric Power
Director of Regulatory Services
101 A Enterprise Drive
P.O. Box 5190
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1. OVERVIEW AND SUMMARY

1. OVERVIEW AND SUMMARY

A. GENERAL REMARKS

Kentucky Power Company (KPCO), authorized to do business in Kentucky as American Electric Power (AEP), is one of the operating companies of the AEP-East System, which is planned and operated on a wholly integrated basis.' In this regard, KPCO's resource plans must be considered in the context of the AEP-East System.

Major structural changes are talcing place in the electric utility industry. Among these is a transition away from the integrated utility generation, transmission, and distribution structure. This system is being replaced by a combination of regional transmission organizations that will have responsibility for planning and operation of the transmission system, along with a generating system that includes both utility and independent generating capacity. Along with this structure a market for generation products is developing, with the major "product" at present (in the East Central Area Reliability Coordination Agreement (ECAR) region) being energy. Simultaneously, the State of Ohio has deregulated generation, mandated corporate separation, and eliminated the concept of native load retail service in favor of competition at retail. This has necessitated the proposal of a modified AEP generation interconnection agreement that will exclude from the AEP-East System the Ohio operating companies, CSP and OPCO. The Restated and Amended Interconnection Agreement among APCo, I&M, KPCO, and the AEP Service Corporation was approved by the Federal Energy Regulatory Commission (FERC) on September 26, 2002. This agreement will not become effective until after Security Exchange Commission (SEC) approval. These three operating companies form the Regulated AEP-East System. Thus, the focus of this report when referring to "AEP System" considerations has shifted from the "old" aggregate AEP-East System in prior reports to the new Regulated AEP-East System in this report. However, historical information (i.e. pre January 1,2003) is generally reported for tlie "old" aggregate AEP-East System.

This report presents the results obtained from evaluations carried out in connection with the development of integrated resource plans for the Regulated AEP-East System and KPCO. The information contained herein includes assumptions relating to overall study parameters and the integration of supply-side resources and demand-side management (DSM) programs.

The AEP System's strategy for complying with Title IV of the Clean Air Act Amendments (CAAA) of 1990, taking into consideration the inception of Phase II of those requirements in the year 2000, includes the continual evaluation of alternative fuel strategies, opportunities to purchase sulfur dioxide (SO_2) allowances, and possible post-combustion technologies in order to lower the overall cost-impact of compliance. Continued use of low and medium sulfur coal, supplemented with SO_2 allowances as needed, and low NOx combustion systems at Big Sandy

[1] 1 The operating companies are: Appalachian Power (APCo); Columbus Southern Power (CSP); Indiana Michigan Power (I&M); Kentucky Power (KPCO); Kingsport Power; Ohio Power (OPCo); and Wheeling Power. All of the AEP operating companies do business as AEP.

Plant will allow that facility to remain in compliance. Big Sandy Plant will be required to meet more stringent NOx emission limitations during the May through September ozone season beginning in May 2004. The compliance plan for Big Sandy Plant to meet this requirement includes installation of an overfire air burner modification and water injection system on Unit 1 and installation of a selective catalytic reduction (SCR) system on Unit 2. The latter installation also requires an upgrade of the Unit 2 electrostatic precipitator. On September 30, 2002 the Company filed with the Commission revisions to the Company's Environmental Compliance Plan at the Big Sandy Generating Plant and an application to recover the associated costs by way of the Environmental Surcharge.

The Integrated Resource Plan (IRP) is based on current mandatory environmental requirements (the existing SO2 reduction program under the CAAA of 1990 and the NOx SIP Call requirements for seasonal NOx reductions in the Midwestern U.S.). However, the IRP does not include the potential impacts of new air emission regulations or air emission legislation (so called 3P and 4P legislation) aimed at further significant reductions in S02, NOx, mercury and in the case of 4P legislation CO2 emission reductions. While it is quite possible that there may be new legislation and/or new regulations governing these pollutants in the future, it is very difficult to predict future legislative and regulatory outcomes. In addition, the EPA is scheduled to propose a Mercury MACT (maximum achievable control technology) standand during 2003. However, it is uncertain the degree of reductions or type of mercury standard likely to be proposed at ths time.

With the additional supply-side resources obtained from the regional generation market and the DSM program effects reflected in the integrated resource plan presented in this report, the AEP System (including KPCO) is expected to have adequate resources to serve its customers' requirements throughout the forecast period.

The AEP System's ability to meet its customers' future electric needs will be affected by the timely completion of planned transmission reinforcement projects, including the Wyoming-Jacksons Ferry 765-kV Project. AEP continues to seek approval of this project.

The planning process is a continuous activity; assumptions and plans are continually reviewed as new information becomes available and modified as appropriate. Indeed, the resource expansion plan reported herein reflects, to a large extent, assumptions that are subject to change; it is simply a snapshot of the future at this time. It is not a commitment to a specific course of action, since the future, now more than ever before, is highly uncertain, particularly in light of the move to increasing competition among suppliers in the marketplace and restructuring in the industry. In this regard, there are a growing number of federal and state initiatives that address the many issues related to industry restructuring and customer choice. Along these lines, ongoing dialogues are continuing with regulators and other interested stakeholders across the AEP System to deal with such issues.

B. PLANNING OBJECTIVES

The primary objective of power system planning is to assure the reliable, adequate, and economical supply of electric power and energy to the consumer in an environmentally compatible manner. Implicit in this primary objective are related objectives, which include, in part: (1) maximizing the efficiency of operation of the power supply system, and (2) encouraging the wise and efficient use of energy. Achievement of these objectives necessarily involves consideration of supply-side options, including various types of generation resources, as well as demand-side options, involving customer load modification programs.

In the planning of power supply resources for the AEP System, consideration is given to several broad factors, including: (1) reliability, i.e., the ability of the system to provide continuous electric service not only under iiormal conditions but also during various contingency conditions; (2) economy, so as to minimize the cost of resources on a long-term basis; (3) environmental compatibility; (4) financial requirements; and (5) flexibility, i.e., the extent to which plans for future resources can be adjusted to meet changing conditions.

C. COMPANY OPERATIONS AND INTERRELATIONSHIP WITH THE AEP SYSTEM

KPCO serves a population of about 389,000 (173,000 retail Customers) in a 3,762 square-mile area in eastern Kentucky. The principal industries served are primary metals, chemicals and allied products, petroleum refining and coal mining. The Company also sells and transmits power at wholesale to other electric utilities, municipalities, electric cooperatives, and non-utility entities engaged in the wholesale power market.

KPCO's internal load usually pealts in the winter; the all-time peak internal demand of 1,579 megawatts (MW) occurred on January 3, 2001. On August 5, 2002, an all-time summer peak internal demand of 1,326 MW was experienced. Of KPCO's total internal energy requirements in 2001, which amounted to 7,392 gigawatt-hours (GWh), residential, commercial, and industrial energy sales accounted for 31.3%, 17.3%, and 42.3%, respectively. Public street and highway lighting, sales for resale, arid all other categories accounted for the remaining 9.1%.

In comparison, the "old" AEP-East System collectively serves a population of about 6.8 million (3.1 million retail customers) in a 41,000 square-mile area in parts of Indiana, Kentucky, Michigan, Ohio, Tennessee, Virginia, and West Virginia. In 2001 the residential, commercial, and industrial customers accounted for 29.1%, 22.8%, and 36.1%, respectively, of the System's total internal energy requirements of 112,488 GWh. The remaining 12.0% was supplied for use in the public street and highway lighting, sales for resale, and all other categories.

The "old" AEP-East System experienced its all-time peak internal demand of 20,402 MW in the summer season of 2002, on August 1. The all-time winter peak internal demand, 19,557 MW, was experienced on February 5, 1996. If sales to non-affiliated power systems are included, the "old" AEP-East System reached its all-time peak total demand of 25,991 MW on June 24,2002.

As of January 1, 2002, KPCO owns and operates the 1,060-megawatt, coal-fired Rig Sandy - . Plant, consisting of an 800-MW unit and a 260-MW unit, at Louisa, Kentucky, and has a unit power agreement with AEP Generating Company, an affiliate, to purchase 390 megawatts of capacity through 2009 and 195 MW of capacity from January 2010 through December 7, 2022 or the end of the lease agreement from the Rockport Plant, located in southern Indiana. In comparison, as of January 1, 2002, the new Regulated AEP-East System's total generating capability will be 12,171 MW (or 11,921 MW, after adjusting for 250 MW of unit power sales), which includes predominantly coal-fired generating units along with conventional hydroelectric, pumped storage, and nuclear capacity.

The AEP System's major eastern operating companies, including KPCO, are electrically interconnected by a high capacity transmission system extending from Virginia to Michigan. This eastern transmission system, consisting of an integrated 765-kV, 500-kV, 345-kV, and 230-kV extra-high-voltage (EHV) network, together with an extensive underlying 138-kV transmission network, and numerous interconnections with neighboring power systems, is planned, constructed, and operated to provide a reliable mechanism to transmit the electrical output from AEP generating plants to the principal load centers and to provide open access transmission service pursuant to FERC Order No. 888.

AEP intends to transfer functional control of transmission facilities in the Eastern part of its system to the PJM Interconnection, LLC a regional transmission organization (RTO) during the first half of 2003. During that time, the PJM RTO will assume the monitoring, market operations and planning responsibilities of these facilities. In addition, PJM will assume the Open Access Same Time Information System (OASIS) responsibility including the evaluation and disposition of requests for transmission services over the AEP transmission system. PJM will also become the North American Reliability council (NERC) Reliablity Coordinator for the AEP transmission system, however, AEP will continue to maintain and physically operate all of its transmission facilities. AEP will retain operational and planning responsibility for those facilities that are not under PJM functional control, and will be involved in the various operations, and planning stakeholder processes of PJM.

D. LOAD FORECASTS

It should be noted that the load forecasts presented herein were developed in August 2002 and do not reflect the experience for the summer season of 2002 and later, or other relevant changes.[2]

KPCO's forecasts of energy consumption for the major customer classes were developed by using both short-term and long-term econometric models. These energy forecasts were determined in part by forecasts of the regional economy, which, in turn, are based on the June

[2] The load forecasts (as well as the historical loads) presented in this report reflect the traditional concept of internal load, i.e., the load that is directly connected to the utility's transmission and distribution system and that is provided with bundled generation and transmission service by the utility. Such load serves as the starting point for the load forecasts used for generation planning. Internal load is a subset of *connected loud,* which also includes directly connected load for which the utility serves only as a transmission provider. Connected load serves as the starting point for the load forecasts used for transmission planning.

2002 national economic forecast of Economy.com (formerly RFA). The forecasts of seasonal peak demands were developed using an analysis similar to EPRI's Hourly Electric Load Model (HELM) that estimates hourly demand.

Some of the key assumptions on which the load forecast is based include:

- moderate U.S. economic growth;
- declining real (inflation-corrected) average electricity prices through 2005; constant real prices thereafter;
- generally slow growth in the Company's service-area population;
- normal weather.

Also, the forecasts for both KPCO and the AEP System reflect the exclusion, beginning in early 2002, of the peak demands of certain sales for resale customers, mainly municipals and cooperatives, who will terminate their contracts for electric power and energy from AEP.

Table 1 provides a *summary* of the "base" forecasts of the seasonal peak internal demands and annual energy requirements for KPCO and the Regulated AEP-East System for the years 2002 to 2016. The forecast data sliown on this table do not reflect any adjustments for current DSM programs. However, inherent in the forecast are the impacts of past customer conservation and load management activities, including DSM programs already in place.

As Table 1 indicates, during the period 2002-2016, KPCO's base internal energy requirements are forecasted to increase at an average annual rate of 1.6%, while the corresponding summer and winter peak internal demands are forecasted to grow at average annual rates of 1.7% and 1.7%, respectively. KPCO's annual peak demand is expected to continue to occur in the winter season.

TABLE 1
KPCO and Regulated AEP-East System
Forecast of Peak Internal Demand and Energy Requirements
Before Adjusting for Expanded DSM Programs
2002-2016

Year	KPCO Peak Internal Demand Summer (MW)	KPCO Peak Internal Demand Winter Following (MW)	KPCO Internal Energy Req'ts (GWh)	Regulated AEP-East System Peak Internal Demand Summer (MW)	Regulated AEP-East System Peak Internal Demand Winter Following (MW)	Regulated AEP-East System Internal Energy Req'ts (GWh)
2002	1,271	1,503	7.676	19,577	16,985	112,596
2003	1,286	1,554	7,702	10,950	11,721	66,163
2004	1,331	1,592	7,993	11,225	11,956	68,044
2005	1,363	1,586	8,150	11,455	12,133	69,169
2006	1,357	1,624	8,125	11,631	12,367	70,331
2007	1,389	1,651	8,322	11,856	12,548	71,698
2008	1,412	1,684	8,480	12,031	12,788	72,936
2009	1,440	1,709	8,620	12,263	12,982	74,108
2010	1,462	1,737	8,750	12,450	13,186	75,234
2011	1,486	1,758	8,884	12,647	13,345	76,378
2012	1,504	1,794	9,037	12,802	13,602	77,648
2013	1,535	1,823	9,189	13,049	13,824	78,899
2014	1,560	1,853	9,336	13,261	14,047	80,166
2015	1,585	1,878	9,489	13,476	14,230	81450
2016	1,606	1,911	9,640	13,651	14,483	82,735
% Average Growth Rate, 2002-2016	1.7	1.7	1 6	-2.5	-11	-22

Note: Regulatec EP-East System Peak Internal Deman ndicated above assumed to aggregate to 307 MW (summer) and 306 MW **(winter)** throughout the forecast period. KPCO does not have such loads.

Similarly, the Regulated AEP-East System's base internal energy requirements during the forecast period are projected to increase at an average annual rate of 1.7% over the 2003-2016 period, while the corresponding summer and winter peak internal demands are projected to grow at average annual rates of 1.7% and 1.6%, respectively. The Regulated AEP-East System's annual peak demand is expected to occur in the winter season.

Table 2 shows KPCO and Regulated AEP-East System load forecast information as in Table 1 except that the peak demands and energy requirements have been reduced, where appropriate, to reflect the impact of the expanded company-sponsored DSM programs assumed to be implemented during the forecast period. A comparison of the data shown on Tables 1 and 2 indicates that the expanded DSM program effects are minor and do not affect the long-term load growth rates.

TABLE 2
KPCO and Regulated AEP-East System
Forecast of Peak Internal Demand and Energy Requirements
After Adjusting for Expanded DSM Programs
2002-2016

	KPCO					
	Peak Internal Demand		**Internal Energy Req'ts (GWh)**	**Peak Internal Demand**		**Internal Energy Req'ts (GWh)**
Year	**Summer (MW)**	**Winter Following (MW)**		**Summer (MW)**	**(MW)**	
2002	1,270	1,502	7,674	19,576	16,984	112,594
2003	1,285	1,552	7,697	11,949	11,719	66,158
2004	1,330	1,589	7,986	11,224	11,953	68,037
2005	1,361	1,582	8,140	11,453	12,129	69,159
2006	1,355	1,620	8,114	11,629	12,363	70,320
2007	1,387	1,647	8,311	11,854	12,544	71,687
2008	1,410	1,680	8,469	12,029	12,784	72,925
2009	1,438	1,705	8,609	12,261	12,978	74,097
2010	1,460	1,733	8,739	12,448	13,182	75,223
2011	1,484	1,754	8,873	12,645	13,341	76,367
2012	1,502	1,790	9,026	12,800	13,598	77,637
2013	1,533	1,819	9,178	13,047	13,820	78,888
2014	1,558	1,849	9,325	13,259	14,043	80,155
2015	1,583	1,874	9,478	13,474	14,226	81,439
2016	1,604	1,907	9,629	13,649	14,479	82,724
% Average Growth Rate, 2002-2016	1.7	1 7	1 6	-25	-11	-2 2

Note: Regulated AEP-East System Peak Internal Demands indicated above include "traditional" interruptible/non-firm **loads, which** are **assumed to aggregate to** 307 MW **(summer) and** 306 MW **(winter) throughout the forecast period.** KPCO **has** no **such loads.**

E. DSM PROGRAMS AND IMPACTS

AEP has offered a variety of conservation and demand-side management programs designed to encourage customers to use electricity efficiently, achieve energy conservation, and reduce the level of future peak demands for electricity. As a result of these energy efficiency programs implemented throughout the AEP jurisdictions, an annual energy savings of about 328 GWh (31 GWh by KPCO customers) and peak demand reductions of 179 MW (22 MW by KPCO customers) in winter and 71 MW (10 MW by KPCO customers) in summer have been achieved by the end of year 2001. For future years, AEP will continue to experience the load impact benefits from these traditional DSM programs, and these load impacts are "embedded" in the base load forecast of the integrated resource plan.

Although the overall effects of past AEP DSM programs will continue to be realized in the future, several recent developments in the restructuring electric utility industry, specifically in the AEP-East service area, have caused AEP to trim down the level of company-sponsored new and/or expanded DSM programs. The emerging competitive environment evolving from restructuring in the electric utility industry and in the AEP System has affected the viability of DSM programs. As a result of recent trends in the regulatory and competitive arenas, the nature of DSM's role has changed to a supplementary and complementary role in utility resources planning over the past few years. Lower supply side resource costs, as a result of competition and other factors, have diminished the economic viability of new or expanded DSM programs. Increased federally mandated energy efficiency standards, together with years of customer educational programs and utility-sponsored DSM programs have improved the energy efficiency of the customers and will continue to do so in the future. Much of the efficiency effects formerly associated with utility-sponsored DSM programs have been captured, or are embedded, in the base load forecast. In addition, while there has always been some uncertainty over projections of DSM impacts, its future has become even more uncertain due to the likelihood of impending electric utility retail competition and cost recovery issues.

The level of DSM activity in each AEP jurisdiction will vary, depending on the regulatory climate, timing of restructuring, various economic factors, such as potential program participation and cost-effectiveness, and the DSM cost recovery mechanisms in that jurisdiction. Currently, DSM programs are expanding in KPCO, but no new recruitment of DSM conservation program participants is assumed in the integrated resource planning for the Regulated AEP-East System beyond the year 2005.

KPCO is fully appreciative of the current regulatory climate and DSM potential in Eastern Kentucky. In this regard, the Company has been continually working with the KPCO DSM Collaborative (which was established in November 1994 to develop KPCO's DSM plans) to ensure that DSM programs are implemented as effectively and efficiently as possible and are helping Kentucky customers save energy. Over the years, the KPCO DSM Collaborative has worked closely in reviewing, recommending and endorsing DSM programs for Kentucky Power. Through continuously monitoring the program performance, program participation level and DSM market potential, the Collaborative has recommended the addition, deletion and modification of various DSM programs for Kentucky Power. These past and present programs, along with DSM programs proposed by the Collaborative for a 3-year extension beyond 2002, are described in detail in the KPCO DSM Collaborative Semi-Annual Status Report and Program Evaluation Reports filed with the Commission on August 14, 2002. On September 24, 2002 the Commission approved the Company's plan to continue the KPCO Collaborative DSM programs through 2005.

TABLE 3
AEP System and KPCO Expanded DSM Programs
Residential Programs:
1. Targeted Energy Efficiency (Low-Income Weatherization)
2. Modified Energy [illegible]
3. High-Efficiency Heat Pump Mobile Home
4. Mobile Home New Construction
Commercial Program
SMART Audit/Incentive
Note: (a) For KPCO, the Residential Modified Energy Fitness Program will be implemented in January 2003, with Commission approval.
(b) For KPCO, the Commercial SMART Audit/Incentive Programs will be discontinued at year-end 2002, with Collaborative approval.

Table **3** lists the DSM programs that are currently being offered in one or more state jurisdictions of the AEP System including Kentucky. This table includes those DSM programs that were approved by the Commission for a three-year extension beyond 2002.

Table 4 provides a summary of the estimated load impacts of implementing the expanded DSM programs for Regulated AEP-East System & KPCO for the years 2002 to 2020, based on the market penetration rates assumed. It was also assumed that there would be no new DSM program participants after the year 2005. Thus, for KPCO, the expanded DSM programs would reduce the base forecast of peak internal demand for the winter season of 2010/11 by an estimated 4 MW (0.2%). In comparison, the summer 2010 peak demand would be reduced by 2 MW. KPCO's corresponding base forecast of internal energy requirements for the year 2010 would be reduced by an estimated 11 GWh.

As Table 4 indicates, the DSM impacts generally increase through about the year 2006 and remain relatively stable until about 2016, decreasing thereafter. Thus, for KPCO, the expanded DSM impact on winter-season peak demand would be reduced from a level of 4 MW in winter 2015/16 to 0 MW in winter 2019/20. These estimated impacts reflect the assumption that new DSM program participants will continue to be added through 2005 in Kentucky.

The projected impacts shown in Table 4 reflect the effects of DSM implementation experience gained thus far while taking into account the latest results of the DSM program evaluations filed with the Commission on August 14, 2002.

The expanded DSM program impacts shown in Table 4 are in addition to the impacts of DSM program installations already in place, i.e., the DSM measures implemented prior to 2002. Such "embedded" DSM impacts are already reflected in the base load forecast. Estimates of these embedded DSM program impacts as of the end of 2001 are shown in the bottom portion of Table 4.

TABLE 4
KPCO and Regulated AEP-East System
Estimated Load Imoacts of Expanded DSM Programs
2002-2020

	KPCO			Regulated AEP East System		
	Demand Reduction			Demand Reduction		
Year	Summer (MW)	Winter Following (MW)	Energy Reduction (GWh)	Summer (MW)	Winter Following (MW)	Energy Reduction (GWh)
2002	0	0	2	0	0	2
2003	1	1	5	1	1	5
2004	1	2	7	1	2	7
2005	1	3	10	1	3	10
2006	2	4	11	2	4	11
2007	2	4	11	2	4	11
2008	2	4	11	2	4	11
2009	2	4	11	2	4	11
2010	2	4	11	2	4	11
2011	2	4	11	2	4	11
2012	2	4	11	2	4	11
2013	2	4	11	2	4	11
2014	2	4	11	2	4	11
2015	2	4	11	2	4	11
2016	2	4	11	2	4	11
2017	1	4	9	1	4	9
2018	1	3	6	1	3	6
2019	1	2	4	1	2	4
2020	0	0	0	0	0	0

not

load forecast Impacts of DSM program installations already in-place, i e , embedded DSM program impacts, are reflected in the base load forecast

As of the end of 2001, the estimated aggregate embedded DSM program impacts were as follows:

	Summer MW	Winter MW	Annual GWh
KPCO	10	22	31
AEP System	71	179	328

Since DSM program persistence is less than 100%, these embedded DSM impacts are expected to diminish gradually over the forecast period.

F. SUPPLY-SIDE RESOURCE EXPANSION

With regard to reserve planning, the ultimate objective of reserve planning is to ensure that adequate operating reserve will be available at all times. (Operating reserve provides for contingencies such as load forecast errors and unplanned generating unit outages, as well as load following and frequency control.) In the old, "single system" planning model, each utility system had to ensure that its own dedicated resources would be adequate to provide such operating reserve. This was accomplislied through the provision of long-term "planning reserves," which provided for both forced and scheduled outages of generating units, unexpected system load growth, etc. Individual system resources were then added to provide adequate "planning reserves."

With the emergence of substantial non-utility generation resource additions to provide resources to the regional market, the focus of utility resource planning has changed. Each system must still provide adequate operating reserves, but "planning reserves" must now be assessed on a regional, rather than an individual system basis. Thus, individual system planning reserves, if any, reflecting only its own dedicated supply-side resources are no longer the major indicator of long-term system reliability.

The AEP System plans to purchase capacity and/or energy from the developing market to provide adequate daily operating reserves. ECAR at present requires a reserve of 4% of the projected daily peak load. AEP has obtained conditional approval from FERC to join PJM as it's RTO selection for AEP's eastern region companies, which includes KPCO. AEP will become a member of PJM and transfer functional control of it's transmission facilities to PJM for inclusion in an expanded PJM-West Region. Additionally, the AEP control area functions will be integrated into the PJM Interchange Energy Market and certain other PJM markets during the first half of 2003. AEP's integration into PJM may require changes in certain operations and planning processes and requirements to ensure reliable and efficient operations of transmission and energy markets within PJM.

Regarding the availability of capacity to be purchased from the market, significant capacity additions have been announced in the ECAR region, of which AEP is a member. The recently issued *Assessment of ECAR-Wide Capacity Margins 2002-2011* indicates that 41,615 MW of new capacity have been announced for installation within the region for the years 2003 through 2007. The study and report estimates that if only 8,734 MW of this new capacity is in service by the year 2006, adequate reliability levels will be maintained. If the announced additions were to be installed (some will most likely be delayed or cancelled) and the peak demand growth projections are accurate, ECAR could see a rise in reserve margins to about 32% by 2005.

Table 5 shows the supply-side resource plan with expanded DSM, along with the corresponding projected Regulated AEP-East System and KPCO peak demands, capabilities, and margins, for the winter and summer seasons, respectively, after adjusting the demands for DSM impacts. (The market purchases included in the reported capabilities are estimated purchases during the week of the seasonal peak, as discussed in Chapter 4.)

Table 5
Projected Peak Demands, Generating Capabilities and Margins
2003 - 2017

	AEP – at time of winter peak (Jan.)				KPCO - at time of winter peak (Jan.)			
Year	**Peak Demand(1) (MW)**	**Capability (MW) (2)**	**Reserve (MW)**	**Margin (%)**	**Peak Demand(1) (MW)**	**Capability (MW) (2)**	**Reserve (MW)**	**Margin (%)**
2003	11,400	12,945	1,545	13.6	1,502	1,450	(52)	(3 5)
2004	11,662	13,095	1,433	12.3	1,552	1,600	48	3 1
2005	11,896	13,345	1,449	12.2	1,589	1,690	101	6 4
2006	12,072	13,545	1,473	12.2	1,582	1,690	108	6 8
2007	12,306	13,795	1,489	12.1	1,620	1,750	130	8.0
2008	12,481	13,995	1,508	12.1	1,647	1,800	153	9 3
2009	12,727	14,295	1,568	12.3	1,680	1,850	170	10 1
2010	12,921	14,500	1,579	12 2	1,705	1,845	140	8 2
2011	13,125	14,700	1,575	12 0	1,733	1,895	162	9 3
2012	13,284	14,900	1,616	12.2	1,754	1,925	171	9 7
2013	13,541	15,200	1,659	12.3	1,790	1,985	195	10 9
2014	13,763	15,450	1,687	12.3	1,819	2,025	206	11 3
2015	13,986	15,700	1,714	12.3	1,849	2,065	216	11 7
2016	14,169	15,900	1,731	12 2	1,874	2,085	211	11 3
2017	14,422	16,150	1,728	12.0	1,907	2,125	218	11 4

Note: (1) Including interruptible load curtailments..
(2) Includes generating facilities and committed and uncommitted purchases as shown in Exhibit 4-12 or 4-14.

Inasmuch as there are many assumptions, each with its own degree of uncertainty, which had to be made in carrying out the resource evaluations, changes in these assumptions could result in significant modifications in the resource plan reflected in Table 5. In this respect, sensitivity analyses indicated that the resource plan is sufficiently flexible to accommodate possible changes in key parameters, including load growth. As such changes are recognized, updated, and more refined, input information must be continually evaluated and resource plans modified as appropriate.

2. LOAD FORECAST

2. LOAD FORECAST

A. SUMMARY OF LOAD FORECAST

A.I. Forecast Assumptions

The load forecasts for KPCO and the other operating companies in the AEP System are based on a forecast of U.S. economic growth provided by Economy.com (formerly RFA). The load forecasts presented herein are based on an Econorny.com economic forecast issued in June 2002 and on AEP load experience prior to 2002. Economy.com projects moderate growth in the U.S. economy during the 2002-2016 forecast period, characterized by a 2.9% annual rise in real Gross Domestic Product (GDP), and moderate inflation as well, with the consumer price index expected to rise by 2.3% per year. Industrial output, as measured by the Federal Reserve Board's (FRB's) index of industrial production, is expected to grow at 2.7% per year during the same period. For the regional economic outlook, the June 2002 forecast developed by Economy.com was utilized. The outlook for KPCO's service area projects employment growth of 1.4% per year during the forecast period and real regional income per-capita growth of 1.8%.

Inherent in the load forecasts are the impacts of past customer energy conservation and load management activities, including company-sponsored demand-side management (DSM) programs already implemented. The load impacts of future, or expanded, DSM programs are analyzed and projected separately, and appropriate adjustments applied to the load forecasts.

A.2. Forecast Highlights

KPCO's total internal energy requirements, before consideration of the effects of expanded DSM programs, are forecasted to increase at an average annual rate of 1.6% from 2002 to 2016. The corresponding summer and winter peak internal demands are forecasted to grow at an average annual rate of 1.7%. KPCO's annual peak demand is expected to continue to occur in the winter season.

The Regulated AEP-East's internal energy requirements during the forecast period are projected to increase at an average annual rate of 1.7% between 2003 and 2016, before consideration of the effects of expanded DSM. Summer and winter peak internal demands are expected to grow at average annual rates of 1.7% and 1.6%, respectively. The Regulated AEP-East annual peak is projected to occur in the winter season.

The load effects of expanded DSM generally increase in time through about the year 2006 and remain relatively stable until about 2016, diminishing thereafter. Over the 20-year forecast period, the projected expanded DSM has little effect on load growth. For both the Regulated AEP-East and KPCO, the expected annual rate of growth in internal energy requirements, as well as in the summer and winter peak internal demands, after accounting for expanded DSM, is unchanged from the growth rate without DSM.

B. OVERVIEW OF FORECAST METHODOLOGY

The Company's load forecasts are based mostly on econometric analyses of time-series data. This method has much to recommend it for load forecasting. One advantage is that it provides a relatively efficient means of producing an internally consistent forecast. This consistency is enforced by the necessity that the model logic be specified in mathematical terms and that all forecast assumptions be defined in quantifiable terms. Another advantage is that it is readily amenable to the consideration of alternate futures through the use of scenario analysis or the development of confidence bands. A third advantage of econometric analysis is that it lends itself to objective verification of models through the application of standard statistical criteria. This aspect is particularly useful in that it facilitates comparisons of forecasting models across companies and across successive forecasts.

In practice, econometric analysis as a general method covers a wide range of specific techniques, and thus raises the issue of choice among alternatives in building and estimating forecasting models. Many of these choices are not obvious and can only be resolved through professional judgment. **A** similar role for professional judgment also exists in the interpretation of the statistical criteria used to judge the performance of the econometric models, which are, likewise, not always clear-cut. In the development of the Company's load forecast, such judgment is informed by a guiding principle, which is to produce as useful and as accurate a forecast as possible, within the constraints imposed by corporate resources and by the availability of data.

In pursuit of that principle, the Company's energy requirements forecast is derived fi-om two sets of econometric models, i.e., a set of monthly short-term models and a set of annual long-term models. This procedure permits easier adaptation of the forecast to the various short- and long-term planning purposes that it serves. For the first full year of the forecast, the forecast values are governed exclusively by the short-term models. The short term models use billed or metered energy sales. The output from the short-term models are adjusted to be unbilled energy sales, which are consistent with the energy generated. The unbilled energy sales forecast is the short-term forecast. For the remaining years of the forecast (2004-2016), the forecast values are determined utilizing the annual growth rates from the long-term models and applying those to the 2003 short-term forecast.

In both sets of models, the major energy classes are analyzed separately. Inputs such as regional and national economic and demographic conditions, energy prices, weather factors, special information (for example, the known plans of specific major customers) and informed judgment are all utilized in producing the forecasts. The major difference between the two sets of models is that the short-term models utilize mostly trend, seasonal and weather variables, while the long-term models utilize "structural" variables, such as per-capita income, employment, energy prices and weather factors, as well as trend variables. Supporting forecasting models are used to predict the future levels of some of the inputs to the long-term energy models. For example, natural gas and coal models are used to predict sectoral natural gas prices and regional coal production. These forecasts then serve as inputs to the respective long-term energy forecasts.

The energy forecast for the total AEP System, by customer class, is obtained by summing the forecasts, by customer class, of each of the AEP operating companies.

The forecast of peak internal demand for the Company is produced by using an analysis similar to EPRI's Hourly Electric Load Model (HELM) that estimates hourly demand based on energy sales forecast, load shapes and weather response fimctions (WRF). The use of forecasted energy requirements in the peak demand models ensures consistency between the Company's peak demand and energy requirements forecasts.

The forecast of peak internal demand for the Regulated AEP-East is determined by summing the operating company hourly demand forecasts.

Flow charts depicting the structure of the models used in projecting KPCO's electric load requirements are shown in Exhibits 2-1 and 2-2. Page 1 of Exhibit 2-1 depicts the stages in the development of the Company's short-term and long-term internal energy requirements forecasts. Page 2 of Exhibit 2-1 identifies in greater detail the variables included in the short-term and long-term energy requirements forecasting models. Exhibit 2-2 presents a schematic of the peak internal demand forecasting model. Displays of model equations, including the results of various statistical tests, along with data sets, are provided in the Appendix.

C. FORECAST METHODOLOGY FOR INTERNAL ENERGY REQUIREMENTS

C.l. General

This section provides a detailed description of the short-term and long-term models employed in producing the forecasts of energy consumption, by customer class, for KPCO. For the purposes of the Company's load forecast, the short term is defined as the first full year of the forecast period, and the long term as anything beyond that.

Conceptually, the difference between the short term and the long term, as it concerns electric energy consumption, has to do with the changes in the stock of electricity-using equipment, rather than with the passage of time. The short term covers the time period during which changes in this stock are minimal, and the long term as the time period during which changes in this stock can be significant. In practice, changes in equipment stocks are related to the passage of time.

In the short term, electric energy consumption is considered to be a function of the utilization of an essentially fixed stock of equipment. For residential and commercial customers, the most significant factor influencing utilization in the short term is weather. For industrial customers, economic forces that determine inventory levels and factory orders also influence short-term utilization rates. The short-term forecasting models recognize these relationships and use weather and the recent trend in load growth, as the primary explanatory variables in forecasting monthly energy sales up to 18 months ahead.

Over time, demographic and economic factors, such as population, employment and income, as well as technology, determine the nature of the stock of electricity-using equipment, in both its size and composition. The long-term forecasting models recognize the importance of these variables and include most of them in the formulation of the long-term energy forecasts.

Relative energy prices also have an impact on electricity consumption. One important difference between the short-term and long-term forecasting models is their treatment of energy prices. Energy prices are not included in the short-term models, but are included in the long-term models. This treatment is justified by consideration of the nature of technological and behavioral constraints on consumer response to price changes. In the short term, these constraints are severe. The presence of durable equipment stocks and the formation of price expectations based in part on past prices mitigates the short-term effect of price changes. In the long term, however, these constraints are lessened as durable equipment is replaced and as price expectations come to fully reflect price changes.

C.2. Short-term Forecasting Models

The goal of KPCO's short-term forecasting models is to produce an accurate load forecast for the first full year into the future. To that end, the short-term forecasting models generally employ a combination of monthly and seasonal binaries, time trends, and monthly heating cooling degree-days in their formulation. The heating and cooling degree-days are measured at weather stations in the Company's service area.

The short-term forecasts were developed utilizing a set of autoregressive integrated moving average (ARIMA) models, which incorporated weather variations. The ARIMA models utilized heating and cooling degree-days and binary variables in the model development. These models were utilized to forecast all sectors.

The estimation period for the short-term inodels was January 1991 through April 2002.

C.2.a. Residential and Commercial Energy Sales

Residential and commercial energy sales are developed using ARIMA models to forecast usage per customer and number of customers. The usage models relate usage to lagged usage, lagged error terms, heating and cooling degree-days and binary variables. The customer models relate customers to lagged customers, lagged error terms and binary variables. The energy sales forecasts are a product of the usage and customer forecasts.

C.2.b. Industrial Energy Sales

The short term industrial energy sales model for KPCO relates energy sales to lagged energy sales, lagged error terms and binary variables. The industrial model is estimated using an ARIMA model.

C.2.c. All Other Energy Sales

The All Other Energy Sales category for KPCO includes public street and highway lighting (or other retail sales) and sales to municipals. KPCO's municipal customers include the cities of Vanceburg and Olive Hill.

Both the other retail and municipal models are estimated using ARIMA models. KPCO's short-term forecasting model for public street and highway lighting energy sales includes binaries, and lagged energy sales. The sales-for-resale model includes binaries, heating and cooling degree days, lagged error terms and lagged energy sales.

C.2.d. Losses and Unaccounted-For Energy

The forecast losses for KPCO are based on an analysis of the historical relationship between energy sales and generation.

C.2.e. Billed/Unbilled Analysis

Unbilled energy sales are forecast using a simple autoregressive model. Estimated gross monthly unbilled energy sales divided by billed energy sales acts as the independent variable. This value, a percentage, is a positive value, which under a hypothetical normal weather scenario, should be about 40%. However, weather and other bookkeeping events cause the percentage to vary. Since the Company forecasts normal weather, the explanatory variables were chosen to estimate average or normal relationships. This was achieved utilizing monthly binary variables. Thus, the implication is that for a particular month, the gross unbilled energy sales is a given percentage of the normal billed energy sales.

The resulting forecast percentage of gross unbilled divided by billed energy is multiplied by the forecast of billed energy sales. Then, mathematical calculations that mirror the computation of net unbilled energy sales are performed resulting in forecast net unbilled energy sales.

C.3. Long-term Forecasting Models

The goal of the long-term forecasting models is to produce a reasonable load outlook for **up** to 20 years in the future. Given that goal, the long-term forecasting models employ a full range of structural economic and demographic variables, electricity and natural gas prices, weather, as measured by annual heating and cooling degree-days, and binary variables to produce load forecasts conditioned on the outlook for the U.S. economy, for the Company's service-area economy, and for relative energy prices.

Most of the explanatory variables enter the long-term forecasting models in a straightforward, untransformed manner. In the case of energy prices, however, it is assumed, consistent with economic theory, that the consumption of electricity responds to changes in the price of electricity or substitute fuels with a lag, rather than instantaneously. This lag occurs for reasons having to do with the technical feasibility of quickly changing the level of electricity use even after its relative price has changed, or with the widely accepted belief that consumers make their consumption decisions on the basis of expected prices, which may be perceived as functions of both past and current prices.

The estimation period for the long-term load forecasting models was 1975-2001. The long-term energy sales forecast is developed by applying the growth rates from the long-term models to the unbilled energy sales forecasts for 2003.

C.3.a. Supporting Models

In order to produce forecasts of certain independent variables used in the internal energy requirements forecasting models, several supporting models are used, including a natural gas price model and a regional coal production model for the KPCO service area. These models are discussed below.

C.3.a.1. Natural Gas Price Model

The forecast price of natural gas used in the Company's energy models comes from a model of state natural gas prices for four primary consuming sectors: residential, commercial, industrial and electric utilities. In the state natural gas price models sectoral prices are related to U.S. sectoral prices, as well as binary variables. The U.S. natural gas price forecasts were obtained from U.S. DOE/EIA's "2002 Annual Energy Outlook". The estimation interval for the natural gas price model, which is an annual model, was 1973-2001.

C.3.a.2. Regional Coal Production Model

A regional coal production forecast is used as an input in the mine power energy sales model. In the coal model, regional production depends mainly on the level of demand for U.S. coal for consumption by electric utilities and U.S. coal production, as well as on binary variables that reflect the impacts of special occurrences, such as strikes. In the development of the regional coal production forecast, projections of U.S. coal production were obtained from U.S. DOE/EIA's "2002 Annual Energy Outlook." The estimation period for the model was 1975-2001.

C.3.b. Residential Energy Sales

Residential energy sales for KPCO are forecasted using two models, the first of which projects the number of residential customers, and the second of which projects kWh usage per customer. The residential energy sales forecast is calculated as the product of the corresponding customer and usage forecasts.

C.3.b.l. Residential Customer Forecasts

The residential customer forecasting model is linear. The level of residential customers is related to total employment in the Company's service area and binary variables. The customer model also employs a lagged dependent variable to represent the gradual adjustment of the number of residential customers to changes in total employment.

C.3.b.2. Residential Energy Usage Per Customer

The kWh usage models are linear, with the independent variables in logarithmic form. Usage is related to service-area total employment, heating and cooling degree-days, the real price of electricity and the real price of natural gas. Both of the energy price terms are five-year moving averages to reflect the delayed effect of prices over time.

Exhibit 2-3 provides a summary of the historical and forecast values of variables used in the development of the Company's residential energy sales forecasts.

C.3.c. Commercial Energy Sales

A single model is used to forecast commercial energy sales. This model is specified as linear, with certain independent variables in logarithmic form. In general, regional economic activity, and relative energy prices are considered to be the primary determinants of long-term commercial load growth. Regional economic activity is represented by regional employment and residential customers serving as another measure of regional economic well-being. Energy prices, represented by the Company's average price of electricity to its commercial customers, and by the statewide real price of natural gas to commercial customers, are included in the model. The model also employs binary variables to account for special occurrences.

Exhibit 2-3 provides a summary of the historical and forecast values of variables used in the development of the Company's commercial energy sales forecasts.

C.3.d. Industrial Energy Sales

C.3.d.l. Manufacturing

The manufacturing forecasting model relates energy sales to real price of natural gas, real price of electricity, FRB production indexes for chemicals and petroleum, service-area manufacturing employment and binary variables. The prices are modeled using five-year moving averages. The dependent and independent variables are modeled as linear, with the production index in logarithmic form.

Exhibit 2-4 provides a summary of the historical and forecast values of variables used in the development of the Company's manufacturing energy sales forecasts.

C.3.d.2. Mine Power

The forecast of KPCO's mine power energy consumption for non-associated mining companies is produced with a model relating mine power energy sales to regional coal production, real price index of petroleum, and average electric price to mine power customers. This model is specified as linear, with the dependent and independent variables in logarithmic form.

Exhibit 2-4 provides a summary of the historical and forecast values of variables used in the development of the mine power energy sales forecast.

C.3.e. All Other Energy Sales

The forecast of public street and highway lighting relates energy sales to service area commercial employment and a binary variable. The model is specified linear with the dependent and independent variables in linear form.

The municipal energy sales model is specified linear with the dependent and independent variables in linear form. Municipal energy sales are modeled relating energy sales to commercial employment, heating and cooling degree days and binary variables. Binary variables are necessary to account for discrete changes in energy sales that result from events such as the addition of new customers or the renegotiation of contracts that increase or decrease energy sales to existing customers. With regard to contractual changes, as a result of notification of contract terminations with Vanceburg and Olive Hill, energy sales are assumed to drop to zero beginning January 1, 2006.

C.3.f. Losses and Unaccounted-For Energy

The forecast losses for KPCO are based on an analysis of the historical relationship between energy sales and generation.

D. FORECAST METHODOLOGY FOR SEASONAL PEAK INTERNAL DEMAND

To forecast peals demand, the Company used algorithms similar to those in the HELM, originally developed by the Electric Power Research Institute. The Company used the methodology to forecast hourly load. Additional inputs in the analysis include weather data, load shapes, transmission and distribution losses, and calendar information. The output from the model includes hourly loads by operating company for the entire forecast period.

The Company used a model that calculates the hourly distribution of loads based on energy sales forecasts, load shapes, and WRFs for system load totals of the operating company. Loads are calculated on an hourly basis and calibrated for weather normalization purposes. The calculated hourly loads for each operating company are added together to form total Regulated AEP East hourly load.

Specifically, the model calculates an hourly load shape for the operating company. The model calculates daily energy based on a WRF. WRFs are defined for all combinations of specified seasons, day types, and daily weather variables. The weather variable used by the model is average daily temperature. The average daily temperature is determined by averaging the daily high and daily low temperatures. The forecast of daily "typical" average temperatures was developed by selecting twelve representative historical months from the past 30-year period (1971 to 2000). These representative months were then combined to form the "typical" or "normal" year.

Different WRFs are defined according to the average temperature values recorded on any given day. WRFs are then applied to weather parameters to yield daily kWh for the operating company. Daily energies are then compared against total annual energy to determine the distribution of energy over the calendar year, resulting in daily energy percentages. These daily percentages are then applied to the annual kWh forecast to determine the daily distribution of forecast energy.

The final step is to allocate the daily energy to hours based on season and day type specific load shapes developed from historical load patterns. Planned demand-side management impacts (modeled independently), an hourly MW load profile, and system loss factors are then added to determine total MW load.

E. LOAD FORECAST RESULTS

E.1. Load Forecast Before DSM Adjustments (Base Forecast)

Exhibit 2-5 present KPCO's annual internal energy requirements, disaggregated by major category (residential, commercial, industrial and other internal sales, as well as losses) on an actual basis for the years 1997-2001 and an a forecast basis for the years 2002-2016. The exhibit also shows annual growth rates for both the historical and forecast periods. Corresponding information for the Regulated AEP-East is given on Exhibit 2-6.

Exhibits 2-7 and 2-8 show, for KPCO and the Regulated AEP-East, respectively, actual and forecasted summer, winter and annual peak internal demands, along with annual total energy requirements. Also shown are the associated growth rates and annual load factors.

Exhibit 2-9 shows further disaggregation of KPCO's forecasted annual internal energy requirements, along with the associated summer and winter peak demands. Exhibits 2-10 and 2-11 show, for the first two years of the forecast period, i.e., 2002 and 2003, KPCO's disaggregated energy requirements on a monthly basis, along with monthly peak demands.

E.2. Load Forecast After DSM Adjustments

Exhibit 2-12 lists the DSM adjustments (discussed in Chapter 3) that were used to reduce the base forecasts of internal energy requirements and seasonal peak internal demands for both the AEP System and KPCO. The resulting forecasts, which reflect these adjustments, are presented in Exhibits 2-13 through 2-19, in the same order as Exhibits 2-5 to 2-11.

F. IMPACT OF CONSERVATION AND DEMAND-SIDE MANAGEMENT

Since the mid-1970s, conservation, caused in part by higher energy prices and in part by Company-sponsored conservation and DSM programs, has reduced the rate of growth of energy sales and peak demand on the entire AEP System and its operating companies.

Higher energy prices have stimulated technological improvements in the energy efficiency of new electric appliances and industrial machinery, and in the thermal integrity of residential and commercial structures. The effect of these improvements has been to decrease average electricity consumption per customer. It is also believed that higher energy prices have had the effect of inducing a permanent change in consumer attitudes toward energy conservation, which has tended to reduce average energy consumption at all levels of price and technological development.

The Company has recognized both its responsibility to encourage its customers to make wise use of all energy resources, and its expertise in the field of energy consumption planning, and has for some years pursued the policy of providing its customers with opportunities to use energy wisely. It has done so through both educational programs and active promotional programs aimed at broad customer groups. And, through its DSM programs, the Company has maintained an active interest and participation in various programs for improving the cost-effectiveness of customer electricity use. Descriptions of the Company's efforts in this regard are given in Chapter 3 of this report.

As for the load forecast, the impact of conservation on load is captured by the inclusion of energy price variables in the forecasting equations. The impact of past customer conservation and load management activities, including embedded DSM installations, is part of the historical record of electricity use, and, in that sense, is intrinsically reflected in the load forecast. As already noted in the preceding section E.2, the load impacts of expanded DSM installations are analyzed and projected separately, and appropriate adjustments are made to the base load forecast.

No explicit adjustments were made to the forecast to account for national appliance efficiency standards or the National Energy Policy Act of 1992. Historically, such legislation and standards have established policies and programs for promoting energy conservation. To the extent that these policies and programs have already been implemented, their effects are intrinsically reflected in the load forecast. However, the effects of the new 12 SEER high efficiency standard for central air conditioner currently being proposed by Congress, was not explicitly reflected in the load forecast.

G. ENERGY-PRICE RELATIONSHIPS

An understanding of the relationship between energy prices and energy consumption is crucial to developing a forecast of electricity consumption. In theory, the effect of a change in the price of a good on the consumption of that good can be decomposed into two effects, the "income" effect and the "substitution" effect. The income effect refers to the change in consumption of a good attributable to the change in real income incident to the change in the price of that good. For most goods, a decline in real income would induce a decline in consumption. The substitution effect refers to the change in the consumption of a good associated with the change in the price of that good relative to the prices of all other goods. The substitution effect is assumed to be negative in all cases; that is, a rise in the price of a good relative to other, substitute goods would induce a decline in consumption of the original good. Thus, if the price of electricity were to rise, the consumption of electricity would fall, all other things being equal. Part of the decline would be attributable to the income effect; consumers effectively have less income after the price of electricity rises, and part would be attributable to the substitution effect; consumers would substitute relatively cheaper fuels for electricity once its price had risen.

The magnitude of the effect of price changes on consumption differs over different time horizons. In the short-term, the effect of a rise in the price of electricity is severely constrained by the ability of consumers to substitute other fuels or to incorporate more electricity-efficient technology. (The fact that the Company's short-term energy consumption models do not include price as an explanatory variable is a reflection of the belief that this constraint is severe).

In the long-term, however, the constraints on substitution are lessened for a number of reasons. First, durable equipment stocks begin to reflect changes in relative energy prices by favoring the equipment using the fuel that was expected to be cheaper; second, heightened consumer interest in saving electricity, backed by willingness to pay for more efficiency, spurs development of conservation technology; third, existing technology, too expensive to implement commercially at previous levels of energy prices, becomes feasible at the new, higher energy prices; and fourth, normal turnover of electricity-using equipment contributes to a higher average level of energy efficiency. For these reasons, energy price changes are expected to have an effect on long-term energy consumption levels. As a reflection of this belief, most of the Company's long-term forecasting models, including the residential, commercial, manufacturing and mine power energy sales models, directly incorporate the price of electricity as an explanatory variable. In these cases, the coefficient of the price variable provides a quantitative measure of the sensitivity of the forecast value to a change in price. Some of the models, including the residential, commercial and manufacturing models, also incorporate the price of natural gas to consumers in the state of Kentucky.

Electricity price prqjections for KPCO are based on two different assumptions governing two different forecast horizons. Through 2005, prices are assumed to be held constant in nominal dollars, i.e., they are expected to decline by the rate of inflation. Beyond 2005, nominal prices are assumed to rise at the expected rate of inflation, thus keeping real prices constant. Given these assumptions, projected electricity prices are expected to fall at an average annual rate of 0.6% for KPCO customers during the period 2002-2016. Natural gas prices to consumers in the state of Kentucky, based on the forecasting model described earlier, are expected to decline by 0.4 % per year during the same period.

H. FORECAST UNCERTAINTY AND RANGE OF FORECASTS

Even though load forecasts are created individually for each of the operating companies in the AEP System, and aggregated to form the System total, forecast uncertainty is of primary interest at the System level, rather than the operating company level. Thus, regardless of how forecast uncertainty is characterized, the analysis begins with AEP System load.

Among the ways to characterize forecast uncertainty are: (1) the establishment of confidence intervals that are defined so as to contain a given percentage of possible outcomes, and (2) the development of high- and low-case scenarios that demonstrate the response of forecasted load to changes in driving force variables. AEP continues to support both approaches to analyzing forecast uncertainty; however, for the purposes of this report, scenarios were used for the sensitivity analyses conducted for capacity planning purposes.

The first step in producing high- and low-case scenarios was the estimation of an aggregated "mini-model" of AEP System internal energy requirements. This approach was deemed more feasible than attempting to calculate high and low cases for each of the many equations used to produce the Company's load forecast. The mini-model is intended to be representative of the full forecasting structure employed in producing the base-case forecast for the AEP System, and, by association, for KPCO. The dependent variable is total AEP System internal energy requirements, excluding sales to the System's aluminum reduction plant. This aluminum load is a large and volatile component of total load, which, as mentioned earlier in this report, is treated judgmentally, not analytically, in the load forecast. It is simply added back, as appropriate, to the alternative forecasts produced by the mini-model to create low- and high-case scenarios for total internal energy requirements. The independent variables are real GDP, AEP service-area employment, the average real price of electricity to all AEP customer classes, the average real price of natural gas in the seven states served by AEP-East, and AEP service-area heating and cooling degree-days. All variables are expressed in logarithms. Acceptance of this particular specification is based on the usual statistical tests of goodness-of-fit, on the reasonableness of the elasticities derived from the estimation, and on a rough agreement between the model's load prediction and that produced by the disaggregated modeling approach followed in producing the load forecast.

Once a base-case energy forecast had been produced with the mini-model, low and high values for the independent variables were determined. The values finally decided upon reflect professional judgment. The low- and high-case growth rates in real GDP for the forecast period were 2.5% and 3.3% per year, respectively, compared to 2.9% for the base case. The low- and high-case growth rates for AEP-region total employment were 0.7% and 1.5% per year, respectively, compared to 1.1% per year for the base case. For the real price of natural gas, the low case assumed a growth rate of 0.4% per year, and the high case assumed a growth rate of 1.2% per year. These compare to a base-case growth rate of 0.8% for the average real gas price in the seven states served by AEP. Electricity price was not varied, the assumption being that variation in the price of natural gas in the high and low cases would serve to represent a change in the relative price of the two fuels. Variations in weather were not considered in this analysis; so the value of heating and cooling degree-days remained the same in all cases.

The low-case, base-case and high-case forecasts of summer and winter peak demands and total energy requirements (before DSM adjustments) for the Regulated AEP-East and KPCO are tabulated in Exhibits 2-20 and 2-21, respectively. Graphical displays of the range of forecasts of internal energy requirements and summer peak demand for KPCO are shown in Exhibit 2-22.

For the Regulated AEP-East, the low-case and high-case energy forecasts for the last forecast year, 2016, represent deviations of about 5.4% below and above, respectively, the base-case forecast (with the corresponding KPCO forecast showing about the same percentage deviation). In this regard, the low-case and high-case growth rates in winter peak internal demand for the forecast period were 1.2% and 1.8% per year, respectively, compared to 1.5% per year in the base case.

The corresponding range of load forecasts reflecting DSM adjustments are shown in Exhibits 2-23 (for the AEP System) and 2-24 (for KPCO).

I. SIGNIFICANT CHANGES FROM PREVIOUS FORECAST

1.1. Energy Forecast

Exhibit 2-25 provides a tabular comparison of the 1999 and 2002 forecasts of total internal energy requirements (before DSM adjustments) for both KPCO and the Regulated AEP-East. Exhibit 2-26 shows the comparison for KPCO in graphical form. As these exhibits indicate, KPCO's 2002 energy forecast is initially higher than the 1999 forecast, but in the long term becomes slightly lower, in terms of magnitude (48 GWh, or 0.5%, lower for year 2016) and long-term average annual growth rate (1.6% vs. 1.7%).

For the Regulated AEP-East, the 2002 forecast for year 2016 is 43.3% less than the 1999 forecast, which primarily reflects the effects of the Regulated AEP-East going from a five member pool to a three member pool in 2003.

An examination of the sectoral changes in the KPCO forecast may provide a better understanding of the changes in the aggregate forecast. The forecasted levels of the sectoral components for the year 2016 did not change uniformly with the 0.5% decrease in the forecast of total energy requirements. Specifically, the residential, commercial, and other retail energy sales forecasts were decreased by 2.7%, 10.2 and 89.5%, respectively, while the industrial sales and losses forecasts were increased by 3.7% and 40.5%, respectively.

Factors contributing to the decrease in the residential and commercial energy sales forecasts include the use of an alternative regional economic forecast (i.e., the forecast by Economy.com) and a re-evaluation of expected long-term trends in residential and commercial consumption patterns in light of what has been experienced historically. The changed assumptions reflect the effect of updated information obtained or developed since the 1999 forecast, along with changing perceptions of the future. The other retail sales forecast change reflects the effects of the contract termination for the two municipals served by the Company.

For the industrial sector, the increase reflects a more optimistic outlook for the industries served by KPCO. The increase in losses better reflects the more recent pattern of losses experienced by the Company.

1.2. Peak Internal Demand Forecast

Exhibit 2-27 provides a tabular comparison of the 1999 and 2002 forecasts of the winter peak internal demand (before DSM adjustments) for both KPCO and the Regulated AEP-East. This exhibit indicates that for the winter of 2016/17, KPCO's 2002 peak demand forecast is 4.0% lower than the 1999 forecast. This decrease reflects the change in the forecast for total energy requirements and an evaluation of the weather normal peak experience.

In the case of the Regulated AEP-East, for the winter of 2016/17, the 2002 forecast is 39.6% lower than the 1999 forecast. This change primarily reflects the change from a five member pool to a three member pool.

1.3. Forecasting Methodology

Opportunities to enhance forecasting methods are explored by KPCO on a continuing basis. In this regard, the Company changed how it models peak demand and short-term industrial energy sales. Peak demand is now estimated using hourly load shapes, weather response functions and average daily temperature. Short-term industrial energy sales are now modeled in aggregate.

The Company now uses Econorny.com as a source for its regional economic forecasts, rather than Woods & Poole Economics.

J. ADDITIONAL LOAD INFORMATION

Additional information provided for the purposes of this report includes the following:

Exhibit 2-28: KPCO, Average Annual Number of Customers by Class, 1997-2001.

Exhibit 2-29: KPCO, Annual Internal Load by Class (GWh), 1997-2001.

Exhibit 2-30: KPCO and AEP System, Recorded and Weather-Normalized Peak Internal Load (MW) and Energy Requirements (GWh), 1997-2001.

Exhibit 2-31: AEP System and KPCO, Profiles of Monthly Peak Internal Demands, 1996, 2001 (Actual), 2011 and 2016.

The historical profiles presented in Exhibit 2-31 have not been adjusted to reflect normal weather patterns and, therefore, may vary to some degree from the forecast patterns projected for 2011 and 2016. These patterns also reflect the expectation that KPCO will continue to experience its annual peak demand in the winter season, while Regulated AEP-East's annual peak is also expected to occur in the winter.

K. DATA-BASE SOURCES

Sources from within the Company that were used in developing the Company's load forecasts are as follows: (1)Sales for Resale Reports (Form ST-18), (2)daily, monthly and annual System Operation Department reports, (3)monthly financial reports, (4)monthly kWh and revenue SIC reports, and (5)residential tariff schedules and fiiel clause summaries for all operating companies.

The data sources from outside the company are varied and include state and federal agencies, as well as Economy.com. Exhibit 2-32 identifies the data series and associated sources, along with notes on adjustments made to the data before incorporation into the load forecasting models.

L. OTHER TOPICS

L.1. Residential Energy Sales Forecast Performance

Exhibit 2-33 provides a comparison of actual vs. the 1999 forecast of KPCO's residential energy sales for the years 1999-2001. In 1999, 2000 and 2001, KPCO's residential energy sales were lower than forecast, by 6.8%, 1.7% and 4.0%, respectively. A major factor contributing to the deviations from forecast was the weather. In 1999, heating degree-days were 7.1% below normal, thus causing less-than-expected energy sales in that year. Likewise, 2001 saw heating degree-days 4.0% below normal, which resulted in residential energy sales being less than expected. However, some over-forecasting occurred in the forecast and thus, the 2002 forecast is somewhat lower than the 1999 forecast.

L.2. Peak Demand Forecast Performance

Exhibit 2-34 provides a comparison of actual vs. the 1999 forecast of KPCO's seasonal internal peak demands for 1999-2001. The exhibit also compares the calculated weather-normalized demands with the forecast values, thus indicating the extent to which weather affected actual demands.

In each winter, KPCO's normalized peaks were less than forecast. Therefore, KPCO's winter peak demand forecast was revised downward.

KPCO's actual and weather-normalized summer peak demands were also mostly below forecast for each year in the period 1999-2002. As a result, KPCO's summer peak demand forecast was revised downward, slightly.

L.3. Other Scenario Analyses

The Company has developed and has begun implementing a plan to be in compliance with the more stringent NOx emission requirements of the Federal EPA's State Implementation Plan (SIP) call. However, it is expected that compliance with these standards will result in higher electricity prices, the magnitude of which has yet to be determined by the Commission. The consumers are expected to respond to these price increases by diminishing their consumption consistent with their relative price elasticities. The net result would be a somewhat lower forecast than presented in this report, all other things being equal. However, the forecast provided herein can be viewed as somewhat conservative in its avoidance of overstating the impacts of these standards.

This forecast incorporates the effects on the membership pool for the Regulated AEP-East. In the previous filing, the Regulated AEP-East was represented by a five-member pool. As a result of deregulation in Ohio and corporate separation, the Regulated AEP-East System is now represented as a three-member pool.

L.4. KPSC Staff Issues Addressed

On June 21, 2000 the Commission issued their Staffs report on KPCO's 1999 Integrated Resource Plan and requested that the Company address certain issues in its next IRP report (this report). The following issues pertaining to load forecasting are restated from the Staff report and addressed below:

1. **Provide a full explanation for any changes in forecasting methodology.**

   See Chapter 2, Section 1.3. where this issue has been addressed.

2. Provide a Comparison of forecasted winter and summer peak demands with actual results for the period following Kentucky Power's 1999 IRP, along with a discussion of the reasons for the differences between forecasted and actual peak demands.

   See Chapter 2, Section I. 2.where this issue has been addressed.

3. Provide a comparison of the annual forecast of residential energy sales, using the current econometric models, with actual results for the period following the 1999 IRP. Include a discussion of the reasons for the differences between forecasted and actual results.

   See Chapter 2, Section L. 1.where this issue has been addressed.

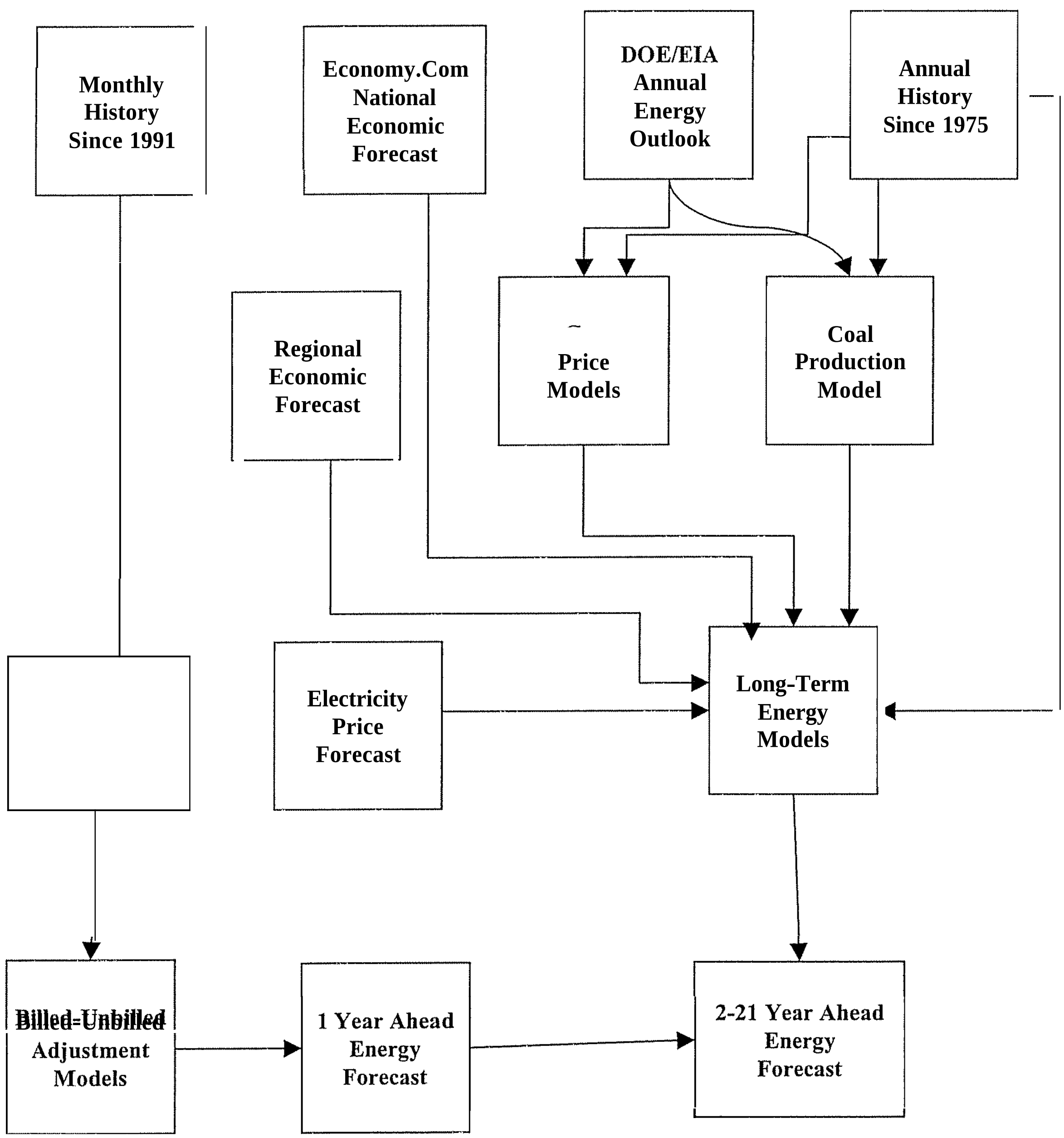
4. Kentucky Power should, to the extent possible, report on and reflect in its forecasts, the impacts of increasing wholesale and retail competition in the electric industry.

   See Chapter 2, Section L.3.where this issued has been addressed.

5. Kentucky Power should attempt, either in its forecasts or in its uncertainty analysis, to incorporate the impacts of potential environmental costs such as those associated with potential NOx reductions imposed on sources in the Eastern United States.

   See Chapter 2, Section L.3.where this issued has been addressed.

Kentucky Power Company
Internal Energy Requirements Forecasting Method

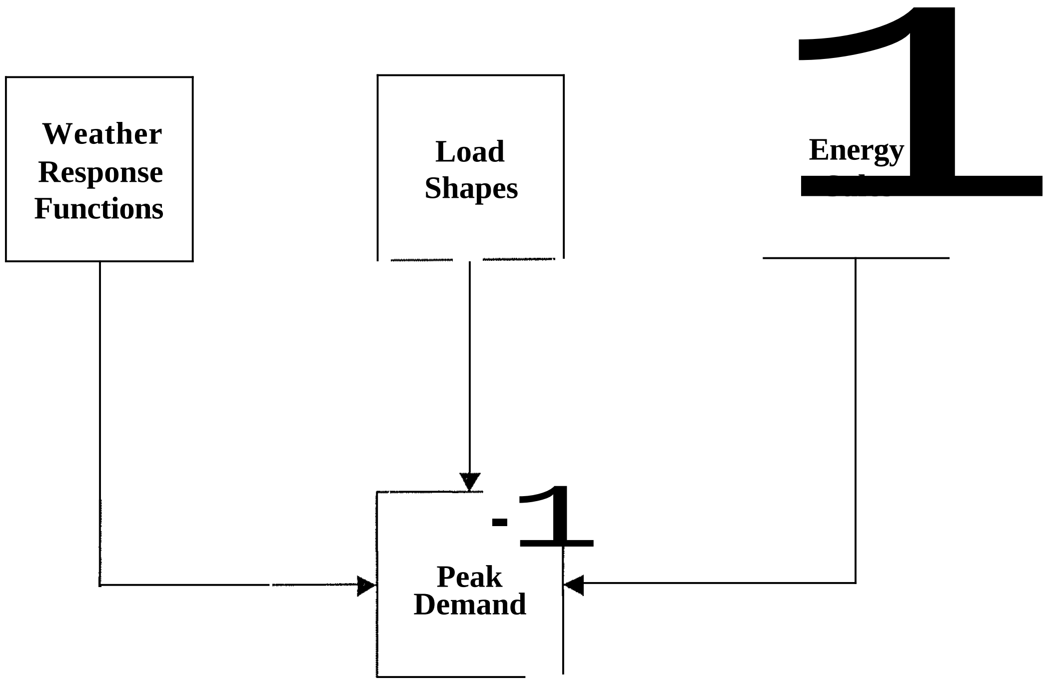


KENTUCKY POWER COMPANY
VARIABLES EMPLOYED IN FORECAST MODELS OF ENERGY SALES

Variable	Residential Customers		Residential Energy Sales		Commercial Customers	Commercial Energy Sales		Total Industrial Energy Sales	Manufacturing Energy Sales	Mine Power Energy Sales	All Other Energy Sales	
	Short Term	Long Term	Short Term	Long Term	Short Term	Short Term	Long Term	Short Term	Long Term	Long Term	Short Term	Long Term
Binary	X	X	X	X	X	X	X	X		X	X	X
Time Trend	X		X		X	X		X			X	X
Electricity Price				X			X		X	X		
Natural Gas Price				X			X		X			
Petroleum Price Index										X		
Residential Customers				X			X					
Service Area Employment		X		X								
Heating Degree-Days			X	X		X					X	X
Cooling Degree-Days			X	X		X					X	X
Commercial Employment							X					
FRB Industrial Production Index									X			X
Manufacturing Employment									X			
Coal Production										X		

Exhibit 2-2

Kentucky Power Company
Peak Internal Demand



Kentucky Power Company
Values of Variables Employed in the Long-Term Forecasts of
Residential and Commercial Energy Sales
1975,2001 and 2016

	Actual 1975	Actual 2001	Forecast Base 2016	Growth Rate - % 1975-2001	Growth Rate - % 2001-2016
Residential Energy Sales					
1. Service Area Employment	95,261	130,784	163,369	1.2	1.5
Residential Customers	106,399	144.079	161,159	1.2	0.7
1. Cooling Degree Days - Huntington, West Virginia	1,274	1,120	1,166	-0.5	0.3
2. Heating Degree Days - Huntington, West Virginia	4,249	4,264	4,520	0.0	0.4
3. Service Area Employment	95,261	130,784	163,369	1.2	1.5
4. Real Residential Electricity Price Index (1997=1.00)	1.72	1.00	0.91	-2.1	-0.6
5. Real Kentucky Residential Gas Price Index (1997=1.00)	0.42	1.00	0.80	3.4	-1.5
Residential Energy Sales (GWH)	972	2,312	3.286	3.4	2.4
Commercial Energy Sales					
1. Residential Customers	106.399	144,079	161,159	1.2	0.7
2. Service Area Commerical Employment	45,441	86,227	119,653	2.5	2.2
3. Real Commercial Electricity Price Index (1997=1.00)	1.73	1.00	0.91	-2.1	-0.6
4. Real Kentucky Commercial Gas Price Index (1997=1.00)	2.60	1.00	1.29	-3.6	1.7
Commercial Energy Sales (GWH)	1,041	2,031	2,587	2.6	1.6

Exhibit 2-3

KPCO z002

Kentucky Power Company
Values of Variables Employed in the Long-Term Forecasts for
Manufacturing and Mine Power Energy Sales
1975,2001 and 2016

	Actual		Forecast	Growth Rate-%	
	1975	2001	Base 2016	1975-2001	2001 2016
Manufacturing Energy Sales					
1. FRB Industrial Production Index for Petroleum (1992=100)	88.0	114.3	176.2	1.0	2.9
2. FRB Industrial Production Index for Chemicals (1992=100)	93.6	121.2	165.9	1.0	2.1
3. Service Area Manufacturing Employment	13,046	8,519	7,124	-1.6	-1.2
4. Real Manufacturing Electricity Price Index (2001=1.00)	1.39	1.00	0.90	-1.3	-0.7
5. Real Kentucky Manufacturing Gas Price Index (2001=1.00)	0.27	1.00	0.80	5.2	-1.5
Manufacturing Energy Sales (GWH)	1,041	1,990	2,737	2.5	2.1
Mine Power Energy Sales					
1. Service Area Coal Production (Million Tons)	61.2	93.5	105.7	1.6	0.8
2. Real Petroleum Price Index (2001=1.00)	0.82	1.00	1.06	0.8	0.4
2. Real Manufacturing Electricity Price Index (2001=1.00)	2.04	1.00	0.91	-2.7	-0.6
Mine Power Energy Sales (GWH)	405	1,071	1,263	3.8	1.1

Kentucky Power Company
Annual Internal Energy Requirements and Growth Rates
1997-2016

Before DSM Adjustments

	Residential Sales		Commercial Sales		Industrial Sales		Other Internal Sales		Losses		Total Internal Energy Requirements	
	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth
Actual												
1997	2,197	--	1,166	--	3,142	--	39	--	304	--	6.897	--
1998	2,156	-1.8	1,195	2.5	3,131	-0.4	91	2.2	419	38.1	6,992	1.4
1999	2,158	0.1	1,231	3.0	3.091	-1.3	91	0.4	535	27.5	7,106	1.6
2000	2,324	7.7	1,244	1.0	3,159	2.2	92	0.9	611	14.4	7,431	4.6
2001	2.312	-0.5	1,279	2.8	3.126	-1.0	91	-1.8	584	-4.5	7,392	-0.5
Forecast												
2002	2.406	4.1	1.340	4.8	3,229	3.3	99	9.1	601	3.0	7,676	3.8
2003	2,435	1.2	1,355	1.1	3.241	0.4	97	-1.6	574	-4.6	7,702	0.3
2004	2,525	3.7	1,396	3.0	3,378	4.2	99	2.1	596	3.8	7,993	3.8
2005	2,580	2.2	1.425	2.1	3,437	1.8	101	1.4	607	2.0	8,150	2.0
2006	2,612	1.2	1,448	1.6	3,448	0.3	12	-87.9	605	-0.3	8.125	-0.3
2007	2,670	2.2	1,478	2.1	3,542	2.7	12	1.6	620	2.4	8,322	2.4
2008	2,723	2.0	1,505	1.9	3,607	1.8	13	1.5	632	1.9	8,480	1.9
2009	2.770	1.7	1,532	1.7	3,662	1.5	13	1.4	642	1.6	8,620	1.6
2010	2,816	1.6	1,558	1.7	3,712	1.4	13	1.4	652	1.5	8,750	1.5
2011	2,864	1.7	1,584	1.7	3,762	1.3	13	1.4	662	1.5	8,884	1.5
2012	2,917	1.9	1.613	1.8	3,820	1.6	13	1.6	673	1.7	9,037	1.7
2013	2,972	1.9	1,641	1.8	3,878	1.5	14	1.5	685	1.7	9,189	1.7
2014	3,025	1.8	1,670	1.7	3,931	1.4	14	1.5	696	1.6	9,336	1.6
2015	3,080	1.8	1,698	1.7	3,989	1.5	14	1.4	707	1.6	9,489	1.6
2016	3,135	1.8	1.726	1.6	4.046	1.4	14	1.4	718	1.6	9.640	1.6
Average Annual Growth Rates:												
1997-2001		3.3		2.3		-0.1		0.4		17.8		1.7
2002-2016		1.9		1.8		1.6		-13.0		1.3		1.6

Note: 2002 data include 6-months actual data and 6-months forecast data.

Exhibit 2-5

KPCO 2002

Regulated AEP-East
Annual Internal Energy Requirements and Growth Rates
1997-2016

Before DSM Adjustments

	Residential Sales		Commercial Sales		Industrial Sales		Other Internal Sales		Losses		Total Internal Energy Requirements	
	GWH	%Growth	GWH	% Growth	GWH	% Growth	GWH	%Growth	GWH	% Growth	GWH	% Growth
Actual												
1997	30,283	--	22,720	--	46,583	--	8,173	--	8,356	--	116.116	--
1998	30,414	0.4	23,599	3.9	47,298	1.5	6,711	-17.9	9,039	8.2	117,061	0.8
1999	31,607	3.9	24,455	3.6	47,352	0.1	5,086	-24.2	8,736	-3.3	117,235	0.1
2000	32.185	1.8	25,216	3.1	42,378	-10.5	4.883	-4.0	9,406	7.7	114,067	-2.7
2001	32,765	1.8	25,656	1.7	40,588	-4.2	4.844	-0.8	8,635	-8.2	112,488	-1.4
Forecast												
2002	33,640	2.7	26.242	2.3	39,437	-2.8	4,919	1.6	8,358	-3.2	112,596	0.1
2003	20,318	-39.6	13,526	-48.5	23,080	-41.5	3.789	-23.0	5.449	-34.8	66,163	-41.2
2004	20,824	2.5	13,993	3.5	23,793	3.1	3,817	0.8	5,616	3.1	68,044	2.8
2005	21,201	1.8	14.300	2.2	24,158	1.5	3,801	-0.4	5,709	1.7	69,169	1.7
2006	21,542	1.6	14,573	1.9	24,607	1.9	3,801	0.0	5,808	1.7	70,331	1.7
2007	21,907	1.7	14,872	2.1	25,116	2.1	3,887	2.3	5,922	2.0	71,698	1.9
2008	22,241	1.6	15.168	2.0	25,527	1.6	3,976	2.3	6,025	1.7	72,936	1.7
2009	22.549	1.4	15,445	1.8	25,931	1.6	4.061	2.1	6,122	1.6	74,108	1.6
2010	22,836	1.3	15,711	1.7	26,325	1.5	4,146	2.1	6,216	1.5	75,234	1.5
2011	23,126	1.3	15.978	1.7	26,733	1.5	4,231	2.0	6,311	1.5	76,378	1.5
2012	23,450	1.4	16,279	1.9	27,174	1.7	4,329	2.3	6,416	1.7	77,648	1.7
2013	23,781	1.4	16,581	1.9	27,596	1.6	4,423	2.2	6.519	1.6	78.899	1.6
2014	24,112	1.4	16,880	1.8	28,036	1.6	4,514	2.1	6,624	1.6	80,166	1.6
2015	24,451	1.4	17.182	1.8	28,482	1.6	4,605	2.0	6.730	1.6	81,450	1.6
2016	24.789	1.4	17,483	1.8	28,932	1.6	4,695	2.0	6,836	1.6	82,735	1.6
Average Annual Growth Rates:												
1997-2001		2.0		3.1		-3.4		-12.3		0.8		-0.8
2002-2016		-2.2		-2.9		-2.2		-0.3		-1.4		-2.2
2003-2016		1.5		2.0		7.8		1.7		1.8		1.7

Note: 2002 data include 6-months actual data and 6-months forecast data.

Exhibit 2-6

KPCO 2002

Kentucky Power Company
Seasonal and Annual Peak Demands, Energy Requirements and Load Factor
1997-2016

Before DSM Adjustments

	Summer Peak			Winter Peak (1)			Annual Peak, Energy and Load Factor				
	Date	MW	% Growth	Date	MW	% Growth	MW	% Growth	GWH	% Growth	Load Factor %
Actual											
1997	07/28/97	1,164	--	03/13/98	1.299	--	1,417	--	6,897	--	55.6
1998	08/25/98	1,213	4.2	01/05/99	1,432	10.2	1,299	-8.3	6.992	1.4	61.4
1999	07/30/99	1,215	0.2	01/27/00	1,558	8.8	1,432	10.2	7,106	1.6	56.7
2000	08/09/00	1,210	-0.4	01/03/01	1,579	1.3	1,558	8.8	7,431	4.6	54.3
2001	08/07/01	1,302	7.6	01/04/02	1,551	-1.8	1,579	1.3	7,392	-0.5	53.4
Forecast											
2002		1,271	-2.4		1.503	-3.1	1,551	-1.8	7,676	3.8	56.5
2003		1,286	1.2		1,554	3.4	1,503	-3.1	7,702	0.3	58.5
2004		1,331	3.4		1,592	2.4	1,554	3.4	7,993	3.8	58.7
2005		1.363	2.4		1,586	-0.4	1,592	2.4	8.150	2.0	58.4
2006		1,357	-0.5		1,624	2.4	1,586	-0.4	8,125	-0.3	58.5
2007		1,389	2.4		1,651	1.7	1,624	2.4	8,322	2.4	58.5
2008		1,412	1.7		1.684	2.0	1,651	1.7	8,480	1.9	58.6
2009		1,440	2.0		1,709	1.5	1,684	2.0	8,620	1.6	58.4
2010		1,462	1.5		1,737	1.6	1,709	1.5	8,750	1.5	58.4
2011		1,486	1.6		1,758	1.2	1,737	1.6	8,884	1.5	58.4
2012		1.504	1.2		1,794	2.0	1,758	1.2	9,037	1.7	58.7
2013		1,535	2.0		1,823	1.6	1,794	2.0	9,189	1.7	58.5
2014		1,560	1.6		1,853	1.7	1,823	1.6	9,336	1.6	58.5
2015		1,585	1.7		1,878	1.3	1.853	1.7	9.489	1.6	58.4
2016		1.606	1.3		1,911	1.8	1.878	1.3	9.640	1.6	58.6
Average Annual Growth Rates:											
1997-2001			2.8			4.5		2.7		1.7	
2002-2016			1.7			1.7		1.4		1.6	

Note: (1) Actual winter peak for year may occur in the 4th quarter of that year or in the 1st quarter of the following year.
Note: **2002** data include 6-months actual data and 6-months forecast data.

Exhibit 2-7

KPCO 2002

Regulated AEP-East

Seasonal and Annual Peak Demands, Energy Requirements and Load Factor

1997-2016

Before DSM Adjustments

	Summer Peak			Winter Peak (I)			Annual Peak, Energy and Load Factor				
	Date	MW	% Growth	Date	MW	% Growth	MW	% Growth	GWH	% Growth	Load Factor %
Actual											
1997	07/14/97	19,119	--	03/13/98	17,841	--	19,381	--	116,116	--	68.4
1998	07/21/98	19,414	I.5	01/05/99	18,546	4.0	19.414	0.2	117,061	0.8	68.8
1999	07/30/99	19,952	2.8	01/28/00	19,167	3.3	19,952	2.8	117.235	0.1	67.1
2000	08/31/01	18.218	-8.7	01/03/01	18,604	-2.9	19,167	-3.9	114,067	-2.7	67.8
2001	08/08/01	20,218	11.0	02/05/02	17,911	-3.7	20,218	5.5	112,488	-1.4	63.5
Forecast											
2002		19,577	-3.2		16,985	-5.2	19,577	-3.2	112,596	0.1	65.7
2003		10,950	-44.1		11,721	-31.0	11,438	-41.6	66,163	-41.2	66.0
2004		11,225	2.5		11,956	2.0	11,721	2.5	68,044	2.8	66.3
2005		11,455	2.0		12,133	1.5	11,956	2.0	69.169	1.7	66.0
2006		11,631	1.5		12,367	1.9	2,133	1.5	70,331	.7	66.2
2007		11,856	1.9		12,548	1.5	2,367	1.9	71,698	.9	66.2
2008		12,031	1.5		12,788	1.9	2,548	1.5	72,936	.7	66.4
2009		12,263	1.9		12,982	1.5	2.788	1.9	74,108	.6	66.2
2010		12,450	1.5		13.186	1.6	2,982	1.5	75,234	.5	66.2
2011		12,647	1.6		13'345	1.2	3,186	I.6	76,378	.5	66.1
2012		12.802	1.2		13,602	1.9	13,345	1.2	77,648	1.7	66.4
2013		13,049	1.9		13,824	1.6	13,602	1.9	78.899	1.6	66.2
2014		13,261	1.6		14,047	1.6	13,824	1.6	80,166	1.6	66.2
2015		13,476	1.6		14,230	1.3	14.047	1.6	81,450	1.6	66.2
2016		13,651	1.3		14,483	1.8	14,230	1.3	82,735	1.6	66.4
Average Annual Growth Rates:											
1997-2001			1.4			0.1		1.1		-0.8	
2002-2016			-2.5			-1.1		-2.3		-2.2	
2003-2016			1.7			1.6		1.7		1.7	

Note: (1)Actual winter peak for year may occur in the 4th quarter of that year or in the 1st quarter of the following year.

Note: 2002 data include 6-months actual data and 6-months forecast data.

Exhibit 2-8

KIC O 2002

Kentucky Power Company
Annual Internal Load
2002-2011

Before DSM Adjustments

Internal Energy (GWH)	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Residential	2,406	2,435	2,525	2,580	2,612	2,670	2,723	2,770	2.816	2,864
Commercial	1,340	1,355	1,396	1,425	1,448	1,478	1,505	1,532	1,558	1,584
Industrial	3,229	3,241	3,378	3.437	3,448	3,542	3,607	3,662	3,712	3,762
Total Other Ultimate	11	12	12	12	12	12	13	13	13	13
Total Ultimate Sales	6,987	7.043	7,310	7,454	7,520	7,702	7,848	7,977	8.098	8,222
Municipals	87	86	87	89	0	0	0	0	0	0
Total Sales-for-Resale	87	86	87	89	0	0	0	0	0	0
Total Internal Sales	7,075	7,128	7,398	7.543	7,520	7,702	7,848	7,977	8,098	8,222
Total Losses	601	574	596	607	605	620	632	642	652	662
Total Internal Energy	7,676	7,702	7,993	8,150	8,125	8,322	8,480	8,620	8,750	8.884

Exhibit 2-9
(Page 1 of 2)

internal Peak Demand (MW)	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Summer	1,271	1,286	1,331	1,363	1,357	1,389	1,412	1,440	1,462	1,486
Preceding Winter	1,551	1,503	1.554	1,592	1,586	1.624	1,651	1.684	1,709	1,737

Note: 2002 data include 6-months actual data and 6-months forecast data.

Kentucky Power Company
Annual Internal Load
2012-2016

Before DSM Adjustments

	2012	2013	2014	2015	2016
Internal Energy (GWH)					
Residential	2.917	2,972	3.025	3,080	3,135
Commercial	1,613	1,641	1,670	1,698	1,726
Industrial	3.820	3,878	3,931	3,989	4,046
Total Other Ultimate	13	14	14	14	14
Total Ultimate Sales	8,364	8,504	8,640	8,782	8.921
Municipals	0	0	0	0	0
Total Sales-for-Resale	0	0	0	0	0
Total Internal Sales	8,364	8,504	8,640	8,782	8,921
Total Losses	673	685	696	707	718
Total Internal Energy	9,037	9,189	9,336	9,489	9,640
Internal Peak Demand (MW)					
Summer	1,504	1,535	1,560	1,585	1,606
Preceding Winter	1,758	1,794	1,823	1,853	1,878

Kentucky Power Company
Monthly Internal Load
2002

Before DSM Adjustments

Internal Energy (GWH)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Residential	327.0	237.0	219.2	151.6	133.5	182.4	194.2	191.7	143.5	169.9	188.6	267.8	2,406
Commercial	118.0	113.8	104.4	96.2	114.2	116.1	118.0	118.6	111.8	105.2	103.4	120.4	1,340
Industrial	258.3	269.4	271.3	264.6	274.8	251.5	276.0	268.0	232.2	284.1	288.1	290.9	3.229
Total Other Ultimate	1.0	1.0	1.0	0.8	0.9	0.7	0.8	0.9	0.8	1.1	1.2	1.2	11
Total Ultimate Sales	704.3	621.3	595.8	513.3	523.4	550.7	589.0	579.1	488.4	560.3	581.3	680.4	6,987
Municipals	11.8	7.5	6.7	7.8	6.1	7.5	7.2	7.5	5.9	5.7	7.2	6.6	87
Total Sales-for-Resale	11.8	7.5	6.7	7.8	6.1	7.5	7.2	7.5	5.9	5.7	7.2	6.6	87
Total Internal Sales	716.1	628.8	602.5	521.1	529.5	558.2	596.2	586.6	494.3	566.0	588.5	687.1	7,075
Total Losses	49.3	48.3	57.7	49.9	48.8	55.7	49.4	48.6	41.0	46.9	48.8	57.0	601
Total Internal Energy	765.4	677.1	660.2	571.0	578.3	613.8	645.6	635.3	535.3	612.9	637.2	744.0	7,676
Internal Peak Demand (MW)	1.551	1,412	1,419	1,106	1,093	1,269	1,248	1,271	1,177	1,025	1,159	1,288	1,551

Note: **2002** data include 6-months actual data and 6-months forecast data.

Exhibit 2-10

Kentucky Power Company
Monthly Internal Load
2003

Before DSM Adjustments

Internal Energy (GWH)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Residential	318.8	246.8	229.7	155.5	144.9	165.6	197.9	191.6	144.7	174.8	191.6	273.6	2,435
Commercial	132.7	105.6	106.5	89.0	100.8	115.0	124.9	120.1	102.7	115.0	111.4	131.5	1,355
Industrial	276.7	255.8	266.0	255.7	268.4	275.1	276.0	268.9	248.6	282.2	281.6	285.6	3,241
Total Other Ultimate	1.2	0.9	1.0	0.8	0.8	0.8	0.8	0.9	0.8	1.1	1.2	1.2	12
Total Ultimate Sales	729.3	609.2	603.3	501.0	515.0	556.4	599.6	581.4	496.8	573.1	585.8	69[illegible]	7,043
Municipals	10.6	8.3	7.1	7.2	5.5	6.6	7.4	7.5	5.9	5.9	7.2	6.4	86
Total Sales-for-Resale	10.6	8.3	7.1	7.2	5.5	6.6	7.4	7.5	5.9	5.9	7.2	6.4	86
Total Internal Sales	739.9	617.5	610.4	508.2	520.5	563.1	607.0	589.0	502.7	579.0	593.0	698.3	7,128
Total Losses	59.5	49.7	49.1	40.9	41.9	45.3	48.8	47.4	40.4	46.6	47.7	56.2	574
Total Internal Energy	799.4	667.2	659.5	549.1	562.4	608.4	655.8	636.3	543.2	625.5	640.7	754.5	7,702
Internal Peak Demand (MW)	1,503	1,353	1,231	1,099	1 119	1,263	1,263	1,286	1 191	1 142	1,173	1,303	1,503

Exhibit 2-12

Regulated AEP-East

Estimated Demand-Side Management Impacts
on Forecasted Energy Requirements and Peak Demands

	Energy Requirements Impacts GWH					Peak Demand impacts MW	
Year	Residential	Commercial	Industrial	Losses	Total	Summer	Winter Following
2002	-1	-1	0	0	-2	-1	-1
2003	-3	-2	0	0	-5	-1	-2
2004	-4	-2	0	-1	-7	-1	-3
2005	-7	-2	0	-1	-10	-2	-4
2006	-8	-2	0	-1	-11	-2	-4
2007	-8	-2	0	-1	-11	-2	-4
2008	-8	-2	0	-1	-11	-2	-4
2009	-8	-2	0	-1	-11	-2	-4
2010	-8	-2	0	-1	-11	-2	-4
2011	-8	-2	0	-1	-11	-2	-4
2012	-8	-2	0	-1	-11	-2	-4
2013	-8	-2	0	-1	-11	-2	-4
2014	-8	-2	0	-1	-11	-2	-4
2015	-8	-2	0	-1	-11	-2	-4
2016	-8	-2	0	-1	-11	-2	-4

Kentucky Power Company
Estimated Demand-Side Management Impacts
on Forecasted Energy Requirements and Peak Demands

	Energy Requirements Impacts GWH					Peak Demand Impacts MW	
Year	Residential	Commercial	Industrial	Losses	Total	Summer	Winter Following
2002	-1	-1	0	0	-2	-1	-1
2003	-3	-2	0	0	-5	-1	-2
2004	-4	-2	0	-1	-7	-1	-3
2005	-7	-2	0	-1	-10	-2	-4
2006	-8	-2	0	-1	-11	-2	-4
2007	-8	-2	0	-1	-11	-2	-4
2008	-8	-2	0	-1	-11	-2	-4
2009	-8	-2	0	-1	-11	-2	-4
2010	-8	-2	0	-1	-11	-2	-4
2011	-8	-2	0	-1	-11	-2	-4
2012	-8	-2	0	-1	-11	-2	-4
2013	-8	-2	0	-1	-11	-2	-4
2014	-8	-2	0	-1	-11	-2	-4
2015	-8	-2	0	-1	-11	-2	-4
2016	-8	-2	0	-1	-11	-2	-4

Kentucky Power Company
Annual Internal Energy Requirements and Growth Rates
1997-2016

Reflecting DSM Adjustments

	Residential Sales		Commercial Sales		Industrial Sales		Other Internal Sales		Losses		Total Internal Energy Requirements	
	GWH	% Growth	GWH	%Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth
Actual												
1997	2,197	--	1.166	--	3,142	--	89	--	304	--	6,897	--
1998	2,156	-1.8	1,195	2.5	3,131	-0.4	91	2.2	419	38.1	6,992	1.4
1999	2,158	0.1	1,231	3.0	3,091	-1.3	91	0.4	535	27.5	7,106	1.6
2000	2,324	7.7	1,244	1.0	3,159	2.2	92	0.9	611	14.4	7,431	4.6
2001	2,312	-0.5	1,279	2.8	3,126	-1.0	91	-1.8	584	-4.5	7,392	-0.5
Forecast												
2002	2,405	4.0	1,339	4.7	3,229	3.3	99	9.1	601	3.0	7,674	3.8
2003	2,432	1.1	1,353	1.0	3,241	0.4	97	-1.6	574	-4.6	7,697	0.3
2004	2,521	3.6	1,394	3.0	3,378	4.2	99	2.1	595	3.7	7,986	3.8
2005	2,573	2.1	1,423	2.1	3,437	1.8	101	1.4	606	2.0	8,140	1.9
2006	2.604	1.2	1,446	1.6	3,448	0.3	12	-87.9	604	-0.3	8,114	-0.3
2007	2,662	2.2	1,476	2.1	3,542	2.7	12	1.6	619	2.4	8.311	2.4
2008	2,715	2.0	1,503	1.9	3,607	1.8	13	1.5	631	1.9	8,469	1.9
2009	2,762	1.8	1,530	1.7	3,662	1.5	13	1.4	641	1.6	8,609	1.6
2010	2,808	1.6	1,556	1.7	3,712	1.4	13	1.4	651	1.5	8,739	1.5
2011	2,856	1.7	1,582	1.7	3,762	1.3	13	1.4	661	1.5	8,873	1.5
2012	2,909	1.9	1,611	1.8	3,820	1.6	13	1.6	672	1.7	9,026	1.7
2013	2,964	1.9	1,639	1.8	3,878	1.5	14	1.5	684	1.7	9,178	1.7
2014	3.017	1.8	1,668	1.7	3,931	1.4	14	1.5	695	1.6	9.325	1.6
2015	3,072	1.8	1,696	1.7	3,989	1.5	14	1.4	706	1.6	9,478	1.6
2016	3.127	1.8	1,724	1.6	4.046	1.4	14	1.4	717	1.6	9,629	1.6
Average Annual Growth Rates:												
1997-2001		1.3		2.3		-0.1		0.4		17.8		1.7
2002-2016		1.9		1.8		1.6		-13.0		1.3		1.6

Note: 2002 data include 6-months actual data and 6-months forecast data.

Exhibit 2-13

KPCO 2002

Regulated AEP-East
Annual Internal Energy Requirements and Growth Rates
1997-2016

Reflecting DSM Adjustments

	Residential Sales		Commercial Sales		Industrial Sales		Other Internal Sales		Losses		Total Internal Energy Requirements	
	GWH	%Growth	GWH	%Growth	GWH	%Growth	GWH	%Growth	GWH	%Growth	GWH	%Growth
Actual												
1997	30,283	--	22,720	--	46,583	--	8,173	--	8,356	--	116.116	--
1998	30,414	0.4	23,599	3.9	47,298	1.5	6,711	-17.9	9,039	8.2	117,061	0.8
1999	31,607	3.9	24,455	3.6	47,352	0.1	5,086	-24.2	8,736	-3.3	117,235	0.1
2000	32,185	1.8	25,216	3.1	42,378	-10.5	4,883	-4.0	9,406	7.7	114,067	-2.7
2001	32,765	1.8	25,656	1.7	40,588	-4.2	4,844	-0.8	8,635	-8.2	112.488	-1.4
Forecast												
2002	33,639	2.7	26,241	2.3	39,437	-2.8	4,919	1.6	8.358	-3.2	112,594	0.1
2003	20.315	-39.6	13.524	-48.5	23,080	-41.5	3,789	-23.0	5,449	-34.8	66,158	-41.2
2004	20,820	2.5	13,991	3.5	23,793	3.1	3,817	0.8	5,615	3.0	68,037	2.8
2005	21.194	1.8	14,298	2.2	24.158	1.5	3,801	-0.4	5,708	1.7	69,159	1.7
2006	21,534	1.6	14.571	1.9	24.607	1.9	3,801	0.0	5,807	1.7	70,320	1.7
2007	21,893	1.7	14,870	2.1	25,116	2.1	3,887	2.3	5,921	2.0	71,687	1.9
2008	22,233	1.6	15,166	2.0	25,527	1.6	3,976	2.3	6,024	1.7	72,925	1.7
2009	22,541	1.4	15,443	1.8	25,931	1.6	4,061	2.1	6,121	1.6	74,097	1.6
2010	22,828	1.3	15,709	1.7	26,325	1.5	4,146	2.1	6,215	1.5	75,223	1.5
2011	23,118	1.3	15.976	1.7	26,733	1.5	4,231	2.0	6,310	1.5	76,367	1.5
2012	23,442	1.4	16,277	1.9	27,174	1.7	4.329	2.3	6,415	1.7	77,637	1.7
2013	23,773	1.4	16,579	1.9	27.596	1.6	4,423	2.2	6,518	1.6	78,888	1.6
2014	24,104	1.4	16,878	1.8	28,036	1.6	4,514	2.1	6,623	1.6	80,155	1.6
2015	24.443	1.4	17,180	1.8	28,482	1.6	4,605	2.0	6,729	1.6	81,439	1.6
2016	24,781	1.4	17,481	1.8	28,932	1.6	4,695	2.0	6,835	7.6	82.724	1.6
Average Annual Growth Rates:												
1997-2001		2.0		3.1		-3.4		-12.3		0.8		-0.8
2002-2016		-2.2		-2.9		-2.2		-0.3		-1.4		-2.2
2003-2016		1.5		2.0		1.8		1.7		1.8		1.7

Note: 2002 data include 6-months actual data and 6-months forecast data.

Exhibit 2-14

KPCO 2002

Kentucky Power Company
Seasonal and Annual Peak Demands, Energy Requirements and Load Factor
1997-2016

Reflecting DSM Adjustments

	Summer Peak			Winter Peak (1)			Annual Peak. Enerav and Load Factor				
	Date	MW	% Growth	Date	MW	% Growth	MW	% Growth	GWH	% Growth	Load Factor %
Actual											
1997	07/28/97	1,164	--	03/13/98	1,299	--	1,417	--	6,897	--	55.6
1998	08/25/98	1,213	4.2	01/05/99	1,432	10.2	1,299	-8.3	6.992	1.4	61.4
1999	07/30/99	1,215	0.2	01/27/00	1,558	8.8	1,432	10.2	7,106	1.6	56.7
2000	08/09/00	1,210	-0.4	01/03/01	1.579	1.3	1,558	8.8	7,431	4.6	54.3
2001	08/07/01	1,302	7.6	01/04/02	1,551	-1.8	1,579	1.3	7,392	-0.5	53.4
Forecast											
2002		1,270	-2.4		1,502	-3.2	1,551	-1.8	7.674	3.8	56.5
2003		1.285	1.2		1,552	3.4	1,502	-3.2	7,697	0.3	58.5
2004		3,330	3.4		1,589	2.4	1,552	3.4	7.986	3.8	58.7
2005		1,361	2.4		1,582	-0.4	1.589	2.4	8,140	1.9	58.5
2006		1,355	-0.5		1,620	2.4	1,582	-0.4	8,114	-0.3	58.5
2007		1,387	2.4		1,647	1.7	1,620	2.4	8,311	2.4	58.6
2008		3,410	1.7		1,680	2.0	1,647	1.7	8,469	1.9	58.7
2009		1,438	2.0		1,705	1.5	1,680	2.0	8,609	1.6	58.5
2010		1,460	1.5		1,733	1.6	1.705	1.5	8,739	1.5	58.5
2011		1,484	1.6		1,754	1.2	1,733	1.6	8.873	1.5	58.4
2012		1,502	1.2		1,790	2.0	1,754	1.2	9,026	1.7	58.7
2013		1,533	2.0		1,819	1.6	1,790	2.0	9.178	1.7	58.5
2014		1,558	1.6		1,849	1.7	1,819	1.6	9,325	1.6	58.5
2015		1,583	1.7		1,874	1.3	7,849	1.7	9,478	1.6	58.5
2016		1,604	1.3		1,907	1.8	1,874	1.3	9,629	1.6	58.7
Average Annual Growth Rates:											
1997-2001			2.8			4.5		2.7		1.7	
2002-2016			1.7			1.7		1.4		1.6	

Note: (1) Actual winter peak for year may occur in the 4th quarter **of** that year or in the **1st** quarter **of** the following year.
Note: **2002** data include 6-months actual data and 6-months forecast data.

Exhibit 2-15

KPCO 2002

Regulated AEP-East
Seasonal and Annual Peak Demands, Energy Requirements and Load Factor
1997-2016

Reflecting DSM Adjustments

	Summer Peak			Winter Peak (1)			Annual Peak, Energy and Load Factor				
	Date	MW	% Growth	Date	MW	% Growth	MW	% Growth	GWH	% Growth	Load Factor %
Actual											
1997	07/14/97	19,119	--	03/13/98	17,841	--	19,381	--	116,116	--	68.4
1998	07/21/98	19,414	1.5	01/05/99	18,546	4.0	19,414	0.2	117,061	0.8	68.8
1999	07/30/99	19,952	2.8	01/28/00	19,167	3.3	19,952	2.8	117,235	0.1	67.1
2000	08/31/01	18,218	-8.7	01/03/01	18,604	-2.9	19,167	-3.9	114,067	-2.7	67.8
2001	08/08/01	20,218	11.0	02/05/02	17.911	-3.7	20,218	5.5	112,488	-1.4	63.5
Forecast											
2002		19,576	-3.2		16,984	-5.2	19,576	-3.2	112,594	0.1	65.7
2003		10,949	-44.1		11,719	-31.0	11,437	-41.6	66.158	-41.2	66.0
2004		11,224	2.5		11,953	2.0	11,719	2.5	68,037	2.8	66.3
2005		11,453	2.0		12,129	1.5	11,953	2.0	69,159	1.7	66.1
2006		11,629	1.5		12,363	1.9	12,129	1.5	70,320	1.7	66.2
2007		11,854	1.9		12.544	1.5	12.363	1.9	71,687	1.9	66.2
2008		12.029	1.5		12,784	1.9	12,544	1.5	72,925	1.7	66.4
2009		12,261	1.9		12,978	1.5	12,784	1.9	74,097	1.6	66.2
2010		12.448	1.5		13,182	1.6	12,978	1.5	75,223	1.5	66.2
2011		12,645	1.6		13,341	1.2	13,182	1.6	76,367	1.5	66.1
2012		12,800	1.2		13,598	1.9	13,341	1.2	77,637	1.7	66.4
2013		13,047	1.9		13,820	1.6	13,598	1.9	78,888	1.6	66.2
2014		13,259	1.6		14.043	1.6	13,820	1.6	80,155	1.6	66.2
2015		13,474	1.6		14,226	1.3	14,043	1.6	81.439	1.6	66.2
2016		13,649	1.3		14.479	1.8	14,226	1.3	82,724	1.6	66.4
Average Annual Growth Rates:											
1997-2001			1.4			0.1		1.1		-0.8	
2002-2016			-2.5			-1.1		-2.3		-2.2	
2003-2016			1.7			1.6		1.7		1.7	

Note: (1)Actual winter peak for year may occur in the 4th quarter of that year or in the 1st quarter of the following year.
Note: 2002 data include 6-months actual data and 6-months forecast data.

Exhibit 2-16

KPCO 2002

Kentucky Power Company

Annual Internal Load

2002-201[redacted]

Reflecting DSM Adjustments

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Internal Energy (GWH)										
Residential	2,405	2,432	2,521	2,573	2,604	2,662	2,715	2,762	2,808	2,856
Commercial	1,339	1,353	1,394	1,423	1,446	1,476	1,503	1,530	1,556	1,582
Industrial	3,229	3,241	3,378	3,437	3,448	3,542	3,607	3,662	3,712	3.762
Total Other Ultimate	11	12	12	12	12	12	13	13	13	13
Total Ultimate Sales	6,985	7.038	7.304	7,445	7,510	7,692	7,838	7,967	8,088	8,212
Municipals	87	86	87	89	0	0	0	0	0	0
Total Sales-for-Resale	87	86	87	39	0	0	0	0	0	0
Total Internal Sales	7,073	7,123	7,392	7.534	7,510	7,692	7,838	7,967	8,088	8.212
Total Losses	601	574	595	606	604	619	631	641	651	661
Total Internal Energy	7,674	7,697	7,986	8,140	8,114	8,311	8,469	8,609	8,739	8,873
Internal Peak Demand (MW)										
Summer	1,270	1.285	1,330	1,361	1,355	1,387	1,410	1.438	1,460	1,484
Preceding Winter	1,550	1,501	1,551	1,588	1,582	1,620	1,647	1,680	1,705	1,733

Note: 2002 data include 6-months actual data and 6-months forecast data.

Kentucky Power Company
Annual Internal Load
2012-2016

Reflecting DSM Adjustments

	2012	2013	2014	2015	2016
Internal Energy (GWH)					
Residential	2,909	2,964	3,017	3,072	3,127
Commercial	1,611	1,639	1.668	1,696	1,724
Industrial	3,820	3,878	3,931	3,989	4,046
Total Other Ultimate	13	14	14	14	14
Total Ultimate Sales	8,354	8,494	8,630	8.772	8,911
Municipals	0	0	0	0	0
Total Sales-for-Resale	0	0	0	0	0
Total internal Sales	8,354	8.494	8,630	8,772	8.911
Total Losses	672	684	695	706	717
Total Internal Energy	9.026	9,178	9,325	9,478	9,629
Internal Peak Demand (MW)					
Summer	1,502	1,533	1,558	1,583	1,604
Preceding Winter	1,754	1,790	1,819	1,849	1,874

Kentucky Power Company
Monthly Internal Load
2002

Reflecting DSM Adjustments

Internal Energy (GWH)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Residential	326.9	236.9	219.1	151.5	133.5	182.3	194.1	191.6	143.5	169.8	188.5	267.7	2,405
Commercial	117.9	713.7	104.3	96.1	114.2	116.1	118.0	118.6	111.8	105.1	103.3	120.3	1.340
Industrial	258.3	269.4	271.3	264.6	274.8	251.5	276.0	268.0	232.2	284.1	288.1	290.9	3,229
Total Other Ultimate	1.0	1.0	1.0	0.8	0.9	0.7	0.8	0.9	0.8	1.1	1.2	1.2	11
Total Ultimate Sales	704.1	621.1	595.6	513.1	523.4	550.6	588.9	579.0	488.4	560.1	581.1	680.2	6,986
Municipals	11.8	7.5	6.7	7.8	6.1	7.5	7.2	7.5	5.9	5.7	7.2	6.6	87
Total Sales-for-Resale	11.8	7.5	6.7	7.8	6.1	7.5	7.2	7.5	5.9	5.7	7.2	6.6	87
Total Internal Sales	715.9	628.6	602.3	520.9	529.5	558.1	596.1	586.5	494.3	565.8	588.3	686.9	7,073
Total Losses	49.3	48.3	57.7	49.9	48.8	55.7	49.4	48.6	41.0	46.9	48.8	57.0	601
Total Internal Energy	765.2	676.9	660.0	570.8	578.3	613.7	645.5	635.2	535.3	612.7	637.0	743.8	7,674
Internal Peak Demand (MW)	1,551	1,412	1,419	1,106	1,093	1.269	1,248	1,271	1.177	1,025	1,159	1,287	1,551

Note: **2002** data include 6-months actual data and 6-months forecast data.

Exhibit 2-18

KPCO 2002

Kentucky Power Company
Monthlv Internal Load
2003

Reflecting DSM Adjustments

Internal Energy (GWH)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Residential	318.5	246.5	229.4	155.2	144.7	165.4	197.7	191.4	144.5	174.5	191.3	273.3	2,432
Commercial	132.5	105.4	106.3	88.8	100.7	114.9	124.8	120.0	102.6	114.8	111.2	131.3	1,353
industrial	276.7	255.8	266.0	255.7	268.4	275.1	276.0	268.9	248.6	282.2	281.6	285.6	3,241
Total Other Ultimate	1.2	0.9	1.0	0.8	0.8	0.8	0.8	0.9	0.8	1.1	1.2	1.2	12
Total Ultimate Sales	728.8	608.7	602.8	500.5	514.7	556.1	599.3	581.1	496.5	572.6	585.3	691.5	7,038
Municipals	10.6	8.3	7.1	7.2	5.5	6.6	7.4	7.5	5.9	5.9	7.2	6.4	86
Total Sales-for-Resale	10.6	8.3	7.1	7.2	5.5	6.6	7.4	7.5	5.9	5.9	7.2	6.4	86
Total Internal Sales	739.4	617.0	609.9	507.7	520.2	562.8	606.7	588.7	502.4	578.5	592.5	697.8	7,123
Total Losses	59.5	49.7	49.1	40.9	41.9	45.3	48.8	47.4	40.4	46.6	47.7	56.2	574
Total Internal Energy	798.9	666.7	659.0	548.6	562.1	608.1	655.5	636.0	542.9	625.0	640.2	754.0	7,697
Internal Peak Demand (MW)	1.502	1,352	1,230	1,099	1,119	1,262	1,262	1,285	1,191	1,142	1,173	1,301	1,502

Exhibit 2-19

KPCO 2002

Regulated AEP-East
Low, Base and High Case for
Forecasted Seasonal Peak Demands and Internal Energy Requirements
2002-2016

Before DSM Adjustments

	Summer Peak Internal Demands (MW)			Winter (Following) Peak Internal Demands (MW)			Internal Energy Requirements (GWH)		
Year	Low Case	Base Case	High Case	Low Case	Base Case	High Case	Low Case	Base Case	High Case
2002	19,341	19,577	19,746	11,694	11,837	11,939	111,241	112,596	113,567
2003	10,788	10,950	11,047	11,892	12,071	12,178	65,184	66.163	66,749
2004	11,042	11,225	11,408	12,096	12,297	12,497	66,933	68,044	69,151
2005	11,250	11,455	11,705	12,302	12,527	12.800	67,929	69,169	70,679
2006	11,392	11,631	11,944	12,495	12,758	13,100	68,881	70,331	72,219
2007	11,586	11,856	12,253	12,671	12,967	13,401	70,064	71,698	74,099
2008	11,721	12.031	12,471	12,804	13,144	13,625	71,052	72,936	75,604
2009	11,909	12.263	12,743	12,938	13,323	13,844	71,966	74,108	77,005
2010	12,051	12,450	12.965	13,069	13,501	14,059	72,825	75,234	78,345
2011	12,197	12,647	13,202	13,192	13,678	14,279	73,662	76.378	79,734
2012	12,300	12,802	13,396	13,314	13,857	14,500	74.606	77,648	81,254
2013	12,488	13,049	13,679	13,422	14,024	14,702	75.511	78,899	82.713
2014	12,645	13,261	13.927	13,533	14,192	14,904	76.441	80,166	84,190
2015	12,803	13,476	14,176	13,643	14,360	15,106	77.383	81,450	85,681
2016	12,919	13,651	14,387	13,748	14,527	15,311	78,299	82,735	87,198
Average Annual Growth Rate %									
2002-2016	-2.8	-2.5	-2.2	1.2	1.5	1.8	-2.5	-2.2	-1.9
2003-2016	1.4	1.7	2.1	1.1	1.4	1.8	1.4	1.7	2.1

Exhibit 2-20

Kentucky Power Company
Low, Base and High Case for
Forecasted Seasonal Peak Demands and Internal Energy Requirements
2002-2016

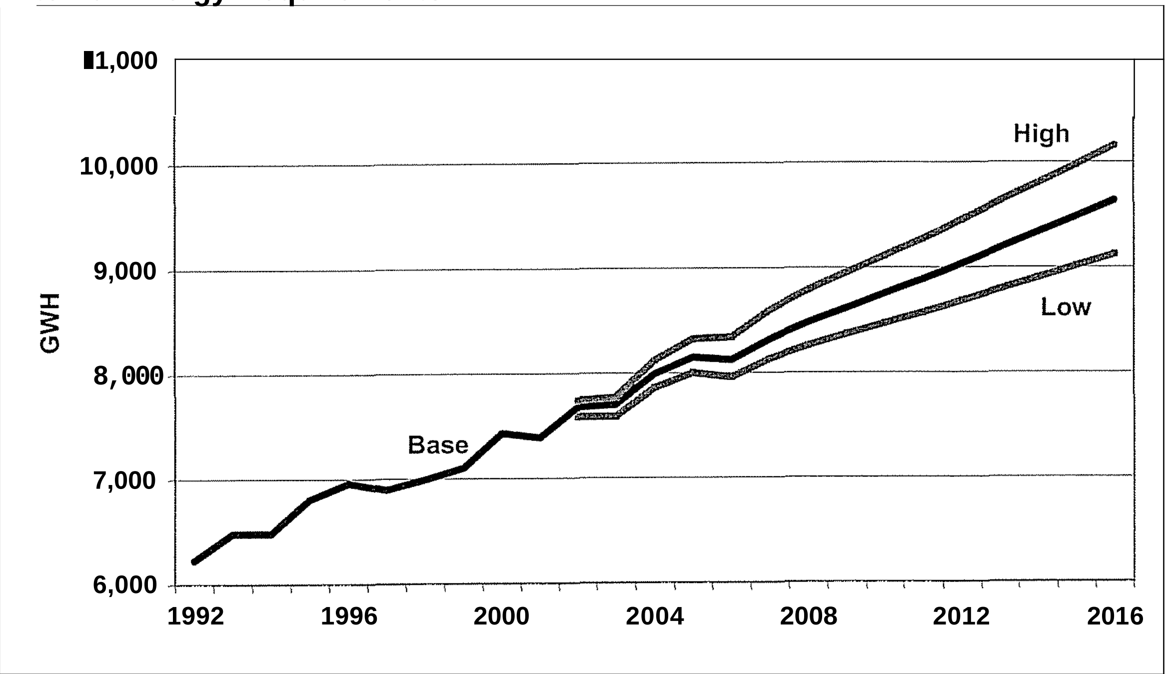
Before DSM Adjustments

	Summer Peak Internal Demands (MW)			Winter (Following) Peak Internal Demands (MW)			internal Energy Requirements (GWH)		
Year	Low Case	Base Case	High Case	Low Case	Base Case	High Case	Low Case	Base ~~Case~~	High ~~Case~~
2002	1.256	1,271	1,282	1,484	1.503	1,515	7,584	7,676	7,742
2003	1,267	1,286	1,298	1,531	1,554	1,568	7,588	7,702	7,770
2004	1,309	1,331	1,352	1,566	1,592	1,618	7,863	7,993	8,123
2005	1,338	1,363	1,393	1,558	1,586	1,621	8,004	8,150	8,328
2006	1,329	1,357	1.393	1,591	1,624	1,668	7,958	8,125	8,343
2007	1,358	1,389	1,436	1,614	1,651	1,707	8,133	8,322	8,601
2008	1,376	1,412	1,464	1,640	1,684	1,745	8,261	8,480	8,790
2009	1.399	1,440	1,496	1,660	1,709	1,776	8,371	8,620	8.957
2010	1,415	3,462	1,523	1,682	1,737	1,809	8,470	8,750	9,112
2011	1,433	1,486	1.551	1,696	1,758	1,836	8,568	8,884	9,275
2012	1,445	1.504	1,574	1,724	1,794	1,877	8,683	9,037	9,457
2013	1,469	1,535	1,609	1,745	1,823	1,911	8,794	9.189	9,633
2014	1,487	1,560	1,638	1,767	1,853	1,946	8,902	9.336	9.805
2015	1,506	1,585	1,668	1,784	1,878	1,975	9,015	9,489	9.981
2016	1,520	1,606	1,693	1,808	1,911	2,014	9,123	9,640	10,160
Average Annual Growth Rate % 2002-2016	1.4	1.7	2.0	1.4	1.7	2.1	1.3	1.6	2.0

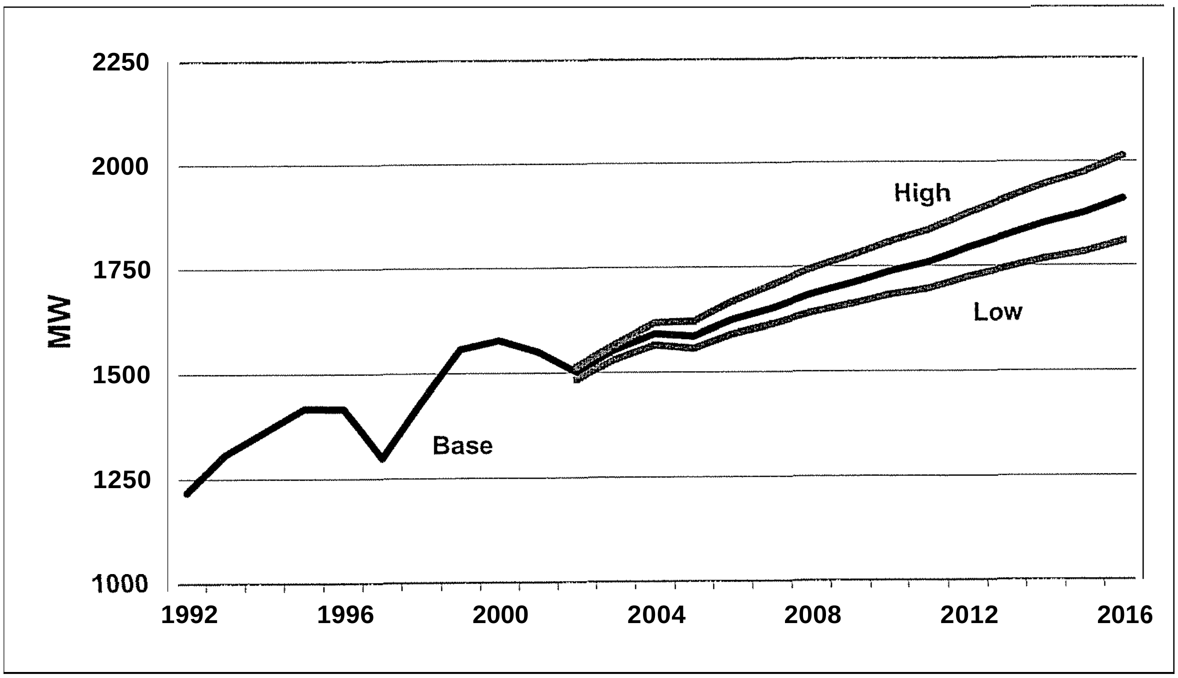
Exhibit 2-22

Kentucky Power Company
Range of Forecasts

nternal Energy Requirements



Winter Peak Demand



Regulated AEP-East
Low, Base and High Case for
Forecasted Seasonal Peak Demands and Internal Energy Requirements
2002-2016

Reflecting DSM Adjustments

	Summer Peak Internal Demands (MW)			Winter (Following) Peak Internal Demands (MW)			Internal Energy Requirements (GWH)		
Year	Low Case	Base Case	High Case	Low Case	Base Case	High Case	Low Case	Base Case	High Case
2002	19,340	19,576	19,745	11,693	11.836	11,938	111,239	112,594	113,565
2003	10,787	10,949	11,046	11,890	12,069	12,176	65,179	66,158	66,744
2004	11,041	11.224	11,407	12,093	12,294	12,494	66,926	68,037	69,144
2005	11,248	11.453	11,703	12,298	12,523	12,796	67.919	69,159	70,669
2006	11,390	11,629	11,942	12,491	12.754	13,096	68,870	70,320	72,208
2007	11,584	11.854	12,251	12,667	12.963	13,397	70,053	71,687	74,088
2008	11,719	12,029	12,469	12,800	13,140	13,621	71,041	72,925	75,593
2009	11,907	12,261	12,741	12,934	13,319	13,840	71,955	74,097	76,994
2010	12,049	12.448	12,963	13,065	13,497	14,055	72,814	75,223	78,334
2011	12,195	12.645	13.200	13,188	13,674	14.275	73.651	76,367	79,723
2012	12,298	12,800	13,394	13,310	13,853	14,496	74,595	77,637	81.243
2013	12,486	13,047	13,677	13,418	14.020	14,698	75.500	78,888	82,702
2014	12,643	13,259	13,925	13,529	14,188	14,900	76,430	80,155	84,179
2015	12,801	13,474	14,174	13,639	14,356	15,102	77,372	81,439	85,670
2016	12.917	13,649	14,385	13,744	14,523	15,307	78,288	82,724	87,187
Average Annual Growth Rate %									
2002-2016	-2.8	-2.5	-2.2	1.2	1.5	1.8	-2.5	-2.2	-1.9
2003-2016	1.4	1.7	2.1	1.1	I.4	1.8	1.4	1.7	2.1

Exhibit 2-23

KPCO 200Z

Kentucky Power Company
Low, Base and High Case for
Forecasted Seasonal Peak Demands and Internal Energy Requirements
2002-2016

Reflecting DSM Adjustments

	Summer Peak Internal Demands (MW)			Winter (Following) Peak Internal Demands (MW)			Internal Energy Requirements (GWH)		
Year	**Low Case**	**Base Case**	**High Case**	**Low Case**	**Base Case**	**High Case**	**Low Case**	**Base Case**	**High Case**
2002	1,255	1,270	1,281	1,483	1,502	1,514	7,582	7,674	7,740
2003	1,266	1.285	1,297	1,529	1,552	1,566	7,583	7,697	7,765
2004	1,308	1,330	1,351	1,563	1,589	1,615	7,856	7.986	8,116
2005	1,336	1,361	1,391	1,554	1,582	1,617	7,994	8,140	8,318
2006	1,327	1,355	1,391	1,587	1,620	1,664	7,947	8,114	8,332
2007	1,356	1,387	1,434	1,610	1,647	1,703	8,122	8.311	8,590
2008	1,374	1,410	1,462	1,636	1,680	1,741	8,250	8,469	8,779
2009	1,397	1,438	1,494	1,656	1,705	1,772	8,360	8,609	8,946
2010	1,413	1,460	1,521	1,678	1,733	1,805	8,459	8.739	9,101
2011	1,431	1,484	1,549	1,692	1,754	1,832	8,557	8,873	9,264
2012	1,443	1,502	1,572	1,720	1,790	1,873	8.672	9,026	9.446
2013	1,467	1,533	1,607	1,741	1,819	1,907	8,783	9,178	9,622
2014	1.485	1,558	1,636	1.763	1,849	1,942	8,891	9,325	9,794
2015	1,504	1,583	1,666	1,780	1,874	1,971	9,004	9,478	9,970
2016	1,518	1,604	1,691	1,804	1,907	2.010	9,112	9,629	10.149
Average Annual Growth Rate % 2002-2016	1.4	1.7	2.0	1.4	1.7	2.0	1.3	1.6	2.0

Exhibit 2-24

KPCO 2002

Kentucky Power Company and Regulated AEP-East
Total Internal Energy Requirements
Comparison of 1999 and 2002 Forecasts

Before DSM Adjustments

Forecast Year	KPCo 2002 Forecast GWH	KPCo 1999 Forecast GWH	KPCo Change From 1996 Forecast GWH	KPCo Change From 1996 Forecast Percent	Regulated AEP-East 2002 Forecast GWH	Regulated AEP-East 1999 Forecast GWH	Regulated AEP-East Change From 1996 Forecast GWH	Regulated AEP-East Change From 1996 Forecast Percent
1999		7,297				118,710		-
2000		7,406				116.116		-
2001		7,524				118,205		
2002	7,676	7,632	44	0.6	112,596	120,268	-7,672	-6.4
2003	7,702	7,746	-44	-0.6	66,163	122,358	-56,195	-45.9
2004	7,993	7,895	98	1.2	68,044	124,168	-56.124	-45.2
2005	8,150	8.045	105	1.3	69,169	125,978	-56,809	-45.1
2006	8,125	8,194	-69	-0.8	70,331	127,788	-57,457	-45.0
2007	8,322	8,343	-21	-0.2	71,698	129,598	-57,900	-44.7
2008	8.480	8.493	-13	-0.2	72,936	131,408	-58,472	-44.5
2009	8.620	8,642	-22	-0.3	74,108	133,219	-59.111	-44.4
2010	8.750	8,792	-42	-0.5	75,234	135,029	-59,795	-44.3
2011	8,884	8,941	-57	-0.6	76,378	136,839	-60,461	-44.2
2012	9,037	9,090	-53	-0.6	77,648	138,649	-61,001	-44.0
2013	9,189	9,240	-51	-0.6	78,899	140,459	-61,560	-43.8
2014	9,336	9,389	-53	-0.6	80.166	142,269	-62,103	-43.7
2015	9,489	9,538	-49	-0.5	81,450	144,079	-62,629	-43.5
2016	9,640	9,688	-48	-0.5	82,735	145,889	-63.154	-43.3
2002-2016 Growth Rate (%)	1.6	1.7			-2.2	1.4		

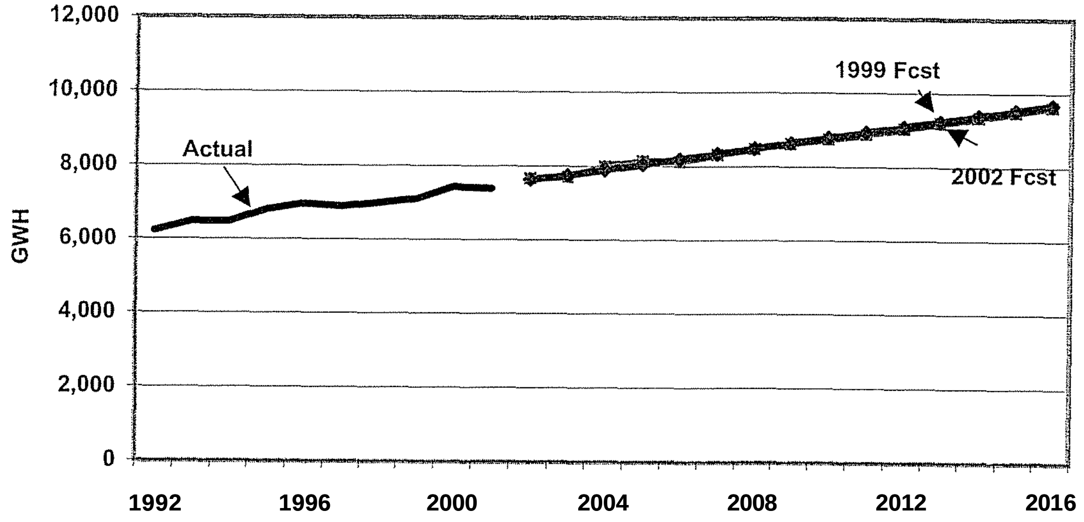
Exhibit 2-25

KPCO 2002

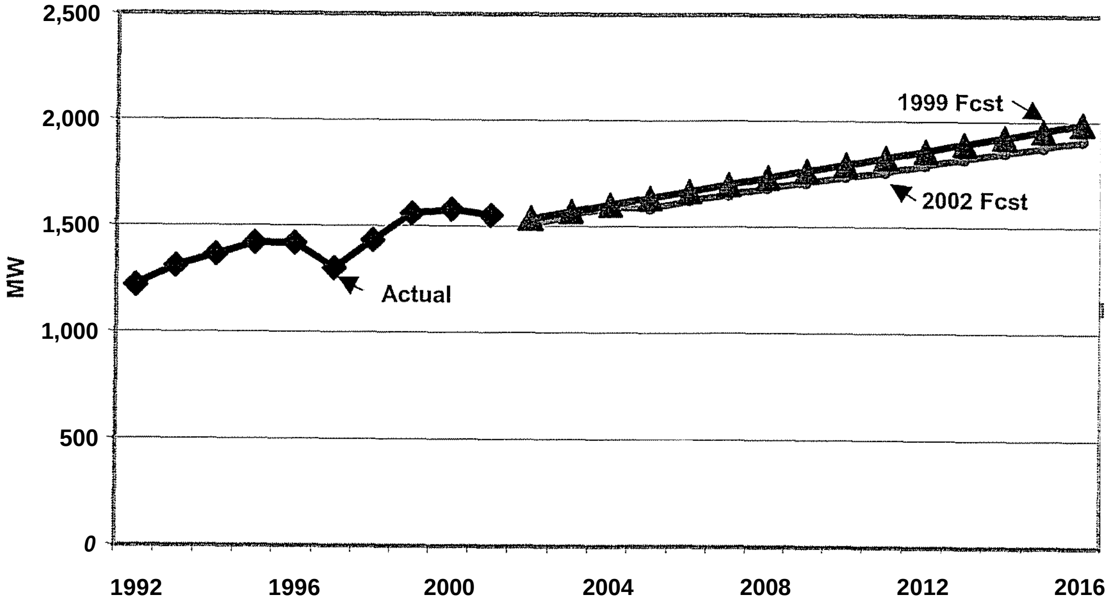
Exhibit *2-26*

Kentucky Power Company
Comparison of Forecasts

Internal Energy Requirements



Winter Peak Demand



Kentucky Power Company and Regulated AEP-East
Winter Peak Internal Demands
Comparison of 1999 and 2002 Forecasts

Before DSM Adjustments

Forecast Year	KPCo 2002 Forecast MW	KPCo 1999 Forecast MW	KPCo Change From 1996 Forecast MW	KPCo Change From 1996 Forecast Percent	Regulated AEP-East 2002 Forecast MW	Regulated AEP-East 1999 Forecast MW	Regulated AEP-East Change From 1996 Forecast MW	Regulated AEP-East Change From 1996 Forecast Percent
1999		1,462				19,082		-
2000		1,488				19.372		-
2001		1,512				19,660		
2002	1,503	1,537	-34	-2.2	16,985	19,955	-2,970	-14.9
2003	1.554	1,570	-16	-1.0	11.721	20,244	-8,523	-42.1
2004	1.592	1.602	-10	-0.6	11,956	20,533	-8,577	-41.8
2005	1,586	1,635	-49	-3.0	12,133	20,821	-8,688	-41.7
2006	1,624	1,667	-43	-2.6	12,367	21,110	-8,743	-41.4
2007	1,651	1,699	-48	-2.8	12.548	21,399	-8,851	-41.4
2008	1,684	1,732	-48	-2.8	12,788	21,687	-8.899	-41.0
2009	1,709	1,764	-55	-3.1	12,982	21,976	-8,994	-40.9
2010	1,737	1,796	-59	-3.3	13,186	22,265	-9,079	-40.8
2011	1,758	1,829	-71	-3.9	13,345	22,553	-9,208	-40.8
2012	1,794	1,861	-67	-3.6	13,602	22.842	-9,240	-40.5
2013	1,823	1,894	-71	-3.7	13,824	23,131	-9,307	-40.2
2014	1,853	1,926	-73	-3.8	14,047	23,419	-9,372	-40.0
2015	1,878	1,958	-80	-4.1	14,230	23,708	-9,478	-40.0
2016	1,911	1,991	-80	-4.0	14.483	23,997	-9.514	-39.6
2002-2016 Growth Rate (%)	1.7	1.9			-1.1	1.3		

Kentucky Power Company
Average Annual Number of Customers by Class
1997-2001

	1997	1998	1999	2000	2001
A. Residential					
1. Heating Customers	71,038	73.288	75,302	77,003	78,244
2. Nonheating Customers	71,160	69,310	67,872	66,649	65,835
3. Total	142,197	142,598	143,174	143,652	144,079
B. Commercial	23,690	24,213	24,782	25,501	25,966
C. Industrial					
1. Manufacturing	1.077	1,065	1,059	976	974
2. Mine Power	613	600	586	550	543
3. Total	1.690	1,664	1,645	1,526	1,517
D. Other Ultimate Sales					
1. Street Lighting	476	499	529	527	447
2. Other	0	0	0	0	0
3. Total	476	499	529	527	447
E. Total Ultimate Sales	168,054	168,974	170,129	471,206	172,009
F. Internal Sales for Resale					
1. Municipals	2	2	2	2	2
2. Other	0	0	0	0	0
3. Total	2	2	2	2	2
G. Total Internal Sales	168.056	168,976	170,131	171.208	172,011

Exhibit 2-28

Kentucky Power Company
Annual Internal Load by Class (GWH)
1997-2001

	1997	1998	1999	2000	2001
A. Residential					
1. Heating Customers	1,399	1,361	1,394	1,534	1,527
2. Nonheating Customers	797	795	765	790	785
3. Total	2,197	2,156	2,158	2,324	2,312
B. Commercial	1 166	1,195	1,231	1,244	1,279
C. Industrial					
1. Manufacturing	2,031	2,021	2,017	2,088	1,990
2. Mine Power	1,111	1,110	1,074	1,071	1,137
3. Total	3,142	3,131	3,091	3,159	3,126
D. Other Ultimate Sales					
1. Street Lighting	10	11	11	11	11
2. Other	0	0	0	0	0
3. Total	10	11	11	11	11
E. Total Ultimate Sales	6,515	6,492	6,491	6,738	6,729
F. Internal Sales for Resale					
1. Municipals	79	81	81	81	79
2. Other	0	0	0	0	0
3. Total	79	81	81	81	79
G. Total Internal Sales	6,593	6,572	6,572	6,819	6,808
H. Losses	304	419	535	611	584
I. Total Internal Load	6,897	6,992	7,106	7,431	7,392

Kentucky Power Company and Regulated AEP-East
Recorded and Weather-Normalized Peak Load (MW) and Energy (GWH)
1997-2001

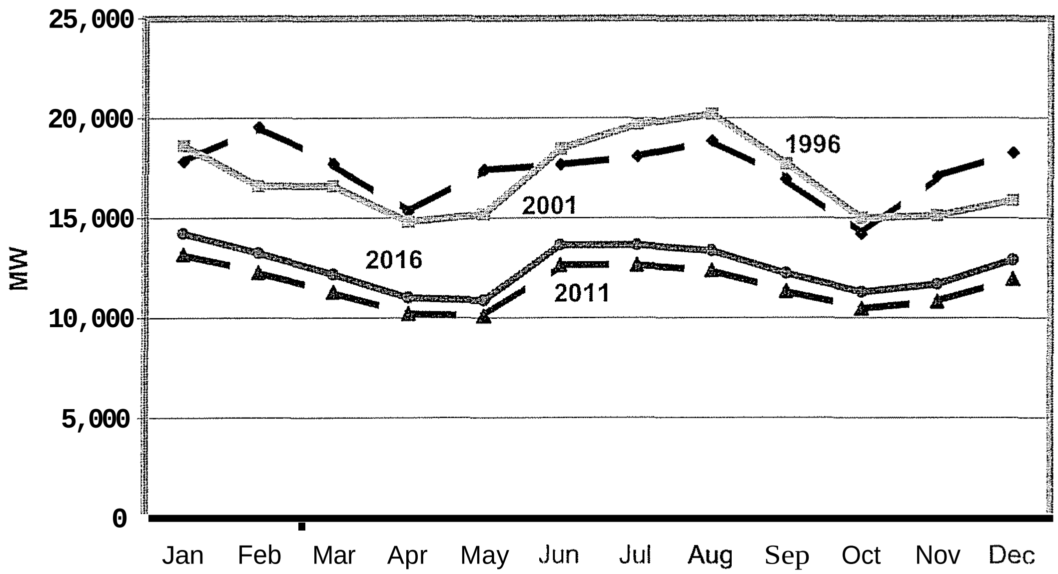
	1997	1998	1999	2000	2001
Kentucky Power Company					
A. Peak Load - Summer					
1. Recorded	1,164	1,213	1,215	1.210	1,302
2. Weather-Normalized	1.165	1,217	1,183	1,264	1,225
B. Peak Load -Winter					
1. Recorded	1,299	1,432	1,558	1,579	1,551
2. Weather-Normalized	1,399	1.413	1,433	1,473	1,495
C. Energy					
1. Recorded	6.897	6,992	7,106	7,431	7,392
2. Weather-Normalized	6,949	7,083	7,134	7,457	7.429
Regulated AEP-East					
A. Peak Load - Summer					
1. Recorded	19,119	19,414	19,952	18,218	20,218
2. Weather-Normalized	19,822	20,117	19,636	19,516	19,218
B. Peak Load -Winter					
1. Recorded	17,841	18.546	19,167	18,634	17,911
2. Weather-Normalized	18,989	18,786	18.405	18,512	18,468
C. Energy					
1. Recorded	116,116	117,061	117,235	114,067	112,488
2. Weather-Normalized	116,779	117,761	117.224	114,387	113.100

Exhibit 2-30

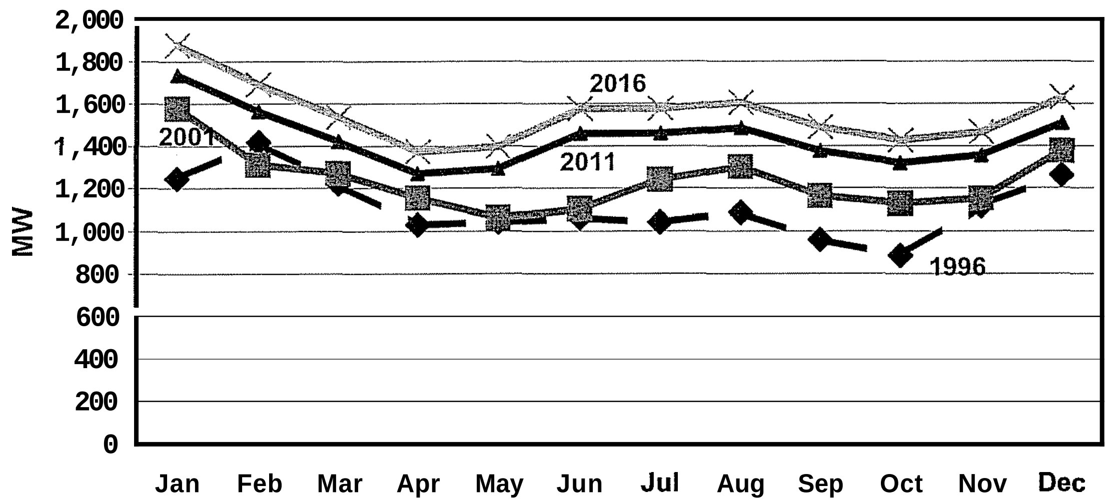
Exhibit 2-31

Regulated AEP-East and Kentucky Power Company
Profiles of Monthly Peak Internal Demands
1996 and 2001 (Actual)
2011 and 2016

Regulated AEP-East



Kentucky Power Company



KENTUCKY POWER COMPANY LOAD FORECAST					
DATA SERIES	FREQUENCY	GEOGRAPHIC	INTERVAL	SOURCE	ADJUSTMENT
Daily Peak Load		throughout the AEP System			
Heating and Cooling Degree-Days	Monthly	Selected weather stations throughout the AEP System	1/75-5102	NOAA (1)	Annual Sums used in long-term models
FRB Production Index, Manufacturing	Monthly and Quarterly	U. S.	1975:1-2002:1 2002:2-2023:4	BOG/FRB (3) Economy Corn (2)	Forecast allocated to months for short-term models: Annual averages used in long-term models
CPI-All Urban Wage Earners	Quarterly	U. S.	1975:1-2023:4	Economy.Com (2)	Annual averages used in long-term models
Index of Producer Prices-Industrial Commodities	Quarterly	U. S.	1975:1-2023:4	Economy.Com (2)	Annual averages used in long-term models
U. S. and Kentucky Natural Gas Prices by Sector	Annually	U. S.	1973-2001	DOE/EIA (4)	None
U. S. Coal Production and Consumption	Annually		1975-2023	DOE/EIA (5)	None
Kentucky Coal Production	Annually	Selected Kentucky Counties	1975-2001	DMMCK (6)	None
Employment (Total and Selected Sectors), Personal Income and Population	Annually	Selected Kentucky Counties	1975-2023	Economy.Com (2)	None

Source Citations:
(1) "Local Climatological Data," National Oceanographic and Atmospheric Administration.
(2) May 2002 Forecast, Economy.Com.
(3) Board of Governors of Federal Reserve System, "Federal Reserve Statistical Release," 1975-2002
(4) U. S. Department of Energy/Energy Information Administration "Natural Gas Monthly" and "Natrual Gas Annual," Selected Issues.
(5) U. S. Department of Energy/Energy Information Administration "2002 Annual Energy Outlook" and "Quarterly Coal Report," Selected Issues.
(6) Department of Mines and Minerals, Commonwealth of Kentucky "Annual Report." Selected Issues.
(7) June 2002 Forecast, Econorny.Com.

Exhibit 2-32

Kentucky Power Company
Residential Energy Sales
1999-2001
Actual vs. 1999 IRP

	Residential Energy Sales -GWH				Heating Degree Days			
Year	Actual	1999 Forecast	GWH Difference	% Difference	Actual	Normal	HDD Difference	% Difference
1999	2,158	2,315	-157	-6.8	4,197	4,520	-323	-7.1
2000	2.324	2,363	-39	-1.7	4,603	4,520	83	1.8
2001	2,312	2,409	-97	-4.0	4,264	4,520	-256	-5.7

Exhibit 2-34

Kentucky Power Company
Seasonal Peak Demands
1999-2001
Actual vs. 1999 Forecast

Summer Peak Demand - MW					Winter Peak Demand - MW				
Summer	Actual	1999 Forecast	MW Difference	% Difference	Winter	Actual	1999 Forecast	MW Difference	% Difference
1999	1,215	1.231	-16	-1.3	1999100	I,558	1,462	96	6.6
2000	1.210	1.250	-40	-3.2	2000/01	1,579	1,488	91	6.1
2001	1,302	1,270	32	2.5	2001/02	1,551	1,512	39	2.6
Summer	Weather Normalized	1999 Forecast	MW Difference	% Difference	Winter	Weather Normalized	1999 Forecast	MW Difference	% Difference
1999	1,183	1,231	-48	-3.9	1999/00	1,433	1.462	-29	-2.0
2000	1,264	1,250	14	1.1	2000101	1,473	1,488	-15	-1.0
2001	1,225	1,270	-45	-3.5	2001/02	1,495	1,512	-17	-1.1

3. DEMAND-SIDE MANAGEMENT PROGRAMS

3. DEMAND-SIDE MANAGEMENT PROGRAMS

A. AEP CONSERVATION & DSM PROGRAMS

AEP has offered a variety of conservation and demand-side management programs designed to encourage customers to use electricity efficiently, conserve energy and utilize cost-effective electrotechnologies. These include a series of information, education, and technical assistance, as well as financial incentive programs for our residential, commercial and industrial customers. As a result of these energy efficiency programs implemented throughout the AEP jurisdictions, an annual energy savings of about 328 GWh (31 GWh by KPCO customers) and peak demand reductions of 179 MW (22 MW by KPCO customers) in winter and 71 MW (10 MW by KPCO customers) in summer have been achieved by the end of year 2001. For fiiture years, AEP will continue to experience the load impacts benefits from these traditional DSM programs and these load impacts are "embedded" in the base load forecast for integrated resources planning purposes.

B. DSM UNDER TRANSITION TO RETAIL ELECTRIC COMPETITION

Although the overall effects of past AEP DSM programs will continue to be realized in the fiiture, several recent pertinent developments in the electric utility industry and specifically in the AEP-East service area, have continuously affected the level of company-sponsored new or expanded DSM programs. These developments have been explained to a certain degree in previous IRP reports filed with the Commission. These developments are the results of (1) the emerging competitive environment evolving from restructuring in the electric utility industry, (2) significant changes in the parameters affecting the economic viability of DSM programs as the result of utility restructuring, (3) continued increased federally mandated energy efficiency standards, and customer education programs, and (4) uncertainties about the future regarding customer choice of energy supplier, and *(5)* DSM cost recovery mechanisms in the AEP System's various state jurisdictions.

First, legislative and regulatory initiatives have been continuously initiated and/or developed, on both the state and federal levels, with the goal of transitioning the electric power industry to operate on a more competitive basis. Currently, this transition may be on a slower pace, however, this process of transition from regulated to the unregulated status has already taken place at different stages in the states that AEP serves. This transition has resulted in the recent AEP corporate separation plan and the related Regulated AEP-East System power pool. With retail open access in Ohio and Michigan, KPCO, for example, is expected to be served under a 3-Company Regulated AEP- East System Power Pool arrangement including Appalachian Power Company, Indiana & Michigan Company and Kentucky Power Company.

Under competition, electric power suppliers can be expected to optimize their operations and compete for a share of the market, based on providing efficient service and fair prices. In this regard, according to economic theory, the fair price of goods and services is ultimately determined in the marketplace. KPCO believes that a properly structured competitive environment will ensure fair and reasonable prices without special attention to DSM. In an environment where energy suppliers compete for customers, DSM services packaged in the suppliers' offerings will be one of the factors upon which customers base their decisions. The marketplace will establish the appropriate level of DSM activity. As examples, some energy efficiency measures, such as power-managed personal computers, "sell themselves" to a large degree at the marketplace now. They have been widely adopted without financial incentives or little utility involvement. Largely occurring through the private sector, energy service companies are also increasing the level of energy efficiency improvement with very little utility involvement. In addition, the marketplace may also determine the appropriate type of DSM activity to implement and by which entity. For example, under "unbundled" generation, transmission and distribution environment, a Demand Response Program (a type of DSM peak clipping program) was initiated by Regional Transmission Organization (RTO) of New England Power Pool (NEPOOL) to manage the peak load condition of the transmission system. The pilot program in NEPOOL is mainly designed to benefit the regional transmission system.

In view of the increasing competition in the industry, it must also be recognized that, the concept of "cost-effectiveness," as applied to DSM, has shifted from the traditional, regulation-based long-term perspective with its special-purpose cost-effectiveness tests, etc., to a more appropriate market-based perspective. In today's environment, and with the associated uncertainty about the future, AEP and other utilities now place greater emphasis on market-based economic analyses. Such analyses are more in line with the Ratepayer Impact Measure (RIM) test and also the utility shareholders' value. Generally speaking, a DSM program that fails the RIM test would, if implemented, result in a rate increase (assuming Commission approval) in a regulated environment. Similarly, a program that requires significant shareholder contribution without notable benefits or the ability to recover the cost will affect the net income of the utility. For the AEP System, together with other factors, this has resulted in a reduction of the expected future number of cost-justified DSM measures and programs.

Secondly, there are significant changes in the parameters affecting the economic viability of DSM programs. Lower supply-side resource costs, as a result of competition in the generation sector and other factors, have diminished the relative economic viability of new or expanded DSM programs. Under proposed corporate separation and the 3 Company power pool, for KPCO the cost effectiveness of the DSM programs are evaluated based on a set of new supply-side resource parameters and resulted in lower supply-side cost projections in the analysis. In the future generation resource plan, for example, the near term generation capacity requirement will be acquired through purchases in the power market instead of building CT's (Combusion Tubines) as assumed in the previous economic analyses. Overall, the Company's resource planning is also now focusing more on a shorter 10-15 year time horizon.

Thirdly, appliance and equipment efficiency standards are having a significant impact on electricity demand. Standards already adopted have significantly reduced electricity use and will continue to do so. Increasing appliance efficiency standards together with years of customer educational programs while complemented by years of utility-sponsored DSM programs will fiirther reduce future electric consumption and improve energy efficiency in the future. Much of the efficiency effects associated with DSM programs have been captured, or are embedded, in the base load forecast.

Lastly, while there has always been a great deal of uncertainty over projections of DSM impacts, the future of DSM has become even more uncertain due to the likelihood of impending electric utility retail competition and cost recovery issues.

As a result of these shifting trends in the regulatory and competitive arenas, the nature of DSM's role has changed to a supplementary and complementary role in utility resource planning. For the AEP System, this has resulted in terminating the future expansion of several DSM programs and reducing the expected future number and overall load impact of DSM programs across the AEP System. However, the level of DSM activity in each AEP jurisdiction will vary, depending on the regulatory climate, timing of restructuring, DSM cost recovery mechnism and various economic factors, such as potential program participation and cost-effectiveness. The Company's current DSM plan has been accordingly modified to reflect these contributing factors in various regions.

KPCO is fully appreciative of the current regulatory climate and DSM potential in Kentucky. In this regard, the Company has been continually working with the KPCO DSM Collaborative (which was established in November 1994 to develop KPCO's DSM plans) to ensure that DSM programs are implemented as effectively and efficiently as possible and are helping Kentucky customers save energy. Over the years, the KPCO DSM Collaborative has worked closely in reviewing, recommending and endorsing DSM programs for Kentucky Power. Through continuous monitoring the program performance, program participation level and DSM market potential, the Collaborative has recommended the addition, deletion and modification of various DSM programs for Kentucky Power. These past and present programs, along with DSM programs proposed by Collaborative for a 3-year extension beyond 2002, are described in detail in the KPCO DSM Collaborative Semi-Annual Status Report and Program Evaluation Reports filed with the Commission on August 14, 2002. The Company has received Commission approval, by order dated September 24, 2002 in Case No. 2002-0304, to continue the KPCO Collaborative DSM programs through 2005. The development of KPCO's DSM programs by the Collaborative incorporated the Collaborative's perspectives on those aspects of integrated resource planning that related to demand-side management.

C. DSM *GOALS* AND OBJECTIVES

Today's DSM programs continue to encourage the wise and prudent use of electricity, stressing activities that are cost-effective, promote efficiency, conserve, and alter consumption patterns. These programs are intended to benefit the consumer and conserve natural resources. The specific objectives of the Company's DSM activities are the same as those detailed in the 1996 and 1999 IRP's:

- Promoting energy conservation to all customers;
- Reducing future peak demands;
- Continuing efforts and cost-effective programs designed to provide the best possible service to customers;
- Promoting electric applications that improve system load factor;
- Striving for retention of existing customers;
- Encouraging new off-peak electrical applications; and

- Providing guidance and assistance to customers facing equipment replacement decisions

To be effective, programs have been tailored to meet local and regional needs and customer characteristics. The Company's two Mobile Home DSM programs and the Targeted Energy Efficiency Program are examples of the programs tailored to meet local and regional needs and customer characteristics.

D. CUSTOMER & MARKET RESEARCH PROGRAMS

Successful demand-side management programs require a thorough Understanding of customer electrical usage characteristics, appliance ownership, conservation activities, demographic characteristics, opinions and attitudes, and, perhaps most importantly, customers' needs for electric service. An understanding of these factors helps in the identification of load modifications, which may be advantageous to both the customer and the Company; permits an assessment of their potential impact; and helps in the development of programs to solicit customer participation. The Company utilizes data from the Company's load research studies, customer surveys, customer billing database and specific program related market research to obtain this information.

Load research and customer billing data were utilized to determine the specific customer and/or end-use demand and energy usage characteristics for DSM program evaluation. End-Use load research metering information, for example, associated with the evaluation of DSM programs on appliances such as heat pump, water heater, air conditioners, fluorescent lighting equipment, etc., has been collected, as appropriate. The information has been utilized in the 2000-2001 DSM program evaluation.

A residential customer survey was conducted for the AEP service area including Kentucky Power in the summer of 2000. The magnitude of this survey was comparable to other surveys conducted since 1980. AEP residential customer surveys are normally implemented at approximately 3-year intervals. The customer survey results are utilized to determine target population size arid the penetration level of various DSM programs.

The market research activities implemented by KPCO have included DSM market/process evaluation studies. These studies focused on assessing participant satisfaction with the various measures included in each DSM program, assisting in determining the impact on demand by persistence and by the number of freeriders, assessing the effectiveness of the program's delivery mechanisms, assisting in determining additional program/product benefits, and gaining insight into market potential. In carrying out these studies, telephone contacts were utilized to conduct telephone interviews with respondents. The sample size varied by program. During 2000-2002, evaluation studies were conducted by selected vendors and KPCO DSM staff for the Mobile Home High-Efficiency Heat Pump Program, Mobile Home New Construction Program, and Targeted Energy Efficiency programs.

E. DSM PROGRAM SCREENING & EVALUATION PROCESS

E.1. Overview

DSM screening has been the foundation of AEP's ongoing evaluation and development of DSM programs. As existing technologies mature, new technologies develop, information on customer responses improves, and economic and other factors change, it has been necessary to re-evaluate older DSM options and open investigations into new options.

Over the years, AEP has performed extensive analyses on a wide range of DSM options, or "measures." The measures that passed the screening process were grouped into programs for potential implementation. Those programs were, in turn, evaluated to determine their appropriateness for individual jurisdictions within the AEP System.

In the case of KPCO, the DSM Collaborative, since its inception in November 1994, has been responsible for performing the function of DSM program screening & evaluation for Kentucky Power. The Collaborative, whose members represent residential, commercial, and industrial customers, was established to develop KPCO's DSM plans, including program designs, budgets and cost-recovery mechanisms. The Collaborative has continued to review the KPCO DSM programs and modify them as appropriate.

As previously indicated, during the past few years, the AEP DSM evaluation process for program screening has been shifted from a societal perspective to a ratepayer perspective to reflect the transition to the upcoming competitive environment, where DSM is expected to be market-based, rather than regulation-based. For KPCO, however, the evaluation process considers the DSM program's cost-effectiveness from all perspectives and incorporates cost-recovery mechanisms, as it has since the inception of the KPCO DSM Collaborative in November 1994. In this regard, the Collaborative decides which DSM programs are to be screened for potential implementation in KPCO's service territory.

Through a continual monitoring process, the Collaborative has utilized a vast amount of data collected from each of the DSM programs to appropriately re-design and re-evaluate the programs so as to improve their cost-effectiveness and better target customers for the programs. Data obtained from load research, customer billing, customer surveys and market research have all been collected from the various DSM programs, and detailed load impacts have been estimated from the information acquired in the field. The Collaborative has provided DSM Status Reports to the Commission every six months since the start of program implementation in 1996, furnishing information on program participation levels, costs and estimated load impacts. Additionally, three KPCO DSM Evaluation Reports were submitted to the Commission, on August 15, 1997, August 16, 1999, and August 14, 2002, respectively. These reports provided extensive results of the screening and evaluation of each of the DSM programs implemented.

E.2. Screening Process

The DSM screening process used by KPCO involved a cost-benefit analysis of each of the DSM programs the Collaborative proposed to continue beyond 2002. This included application of the previously mentioned TRC and RIM tests, as well as the "Utility Cost" (UC) test and the "Participant" (P) test, as defined in the California Standard Practice Manual. In this connection, the evaluation of the cost-effectiveness of a given DSM program involves the determination of the net present worth of the program's benefits and costs over the study period, which, in this case, was 2002-2021. Under the TRC test, such benefits and costs are viewed from the combined perspective of the utility and the program participant, whereas under the RIM test, the benefits and costs are viewed from the perspective of the ratepayer. The benefits and costs under the UC test are viewed from the perspective of the utility, and under the P test, from the perspective of the program participant.

The major supply-side benefits used in the cost-benefit analysis of DSM programs are avoided energy (production) costs and avoided demand/capacity costs (for generation, transmission and distribution). These costs are valued on a marginal $/MWh and/or $/kW basis, as appropriate. A detailed approach (peak and off-peak periods, by season) was used to develop avoided production costs. Marginal production costs at peak and off-peak periods in the summer and winter seasons were applied to the appropriate DSM program impacts. The marginal production costs were estimated year-by-year for the forecast period based on a production cost computer model.

Currently, under a 3-Company Regulated AEP- East System Power Pool arrangement for AEP/Kentucky, the future generation capacity requirement will be acquired through purchase in the power market. Hence, the generation capacity costs are also valued, as in the case of production cost, on a $/MWh basis. For cost benefit evaluation of DSM programs, the avoided generation capacity costs are combined with production costs as a single entity in the production cost computer model. Avoided costs for transmission and distribution, valued in $/kW, were estimated based on historical and projected capital expenditures for general system development projects that are related to load growth.

The benefits, costs and load impacts estimated in the cost-benefit analysis reflect the assumptions regarding replacement and persistence of each measure within the DSM programs over the study period. Also, the analysis considered the benefits from SO_2 emission credits, NO_X market price, and expected additional system sales, thereby improving the cost effectiveness of each DSM measure. The reductions in CO_2 emissions can be estimated in the evaluation; however, no specific dollar values were assigned to them. There are currently no regulations that limit CO_2 emissions.

E.3. Screening & Evaluation Results

The Company, working with the Collaborative, has re-screened and re-evaluated the current on-going DSM programs and the expanded programs filed for a three-year extension with the Commission on August 14, 2002. Additional measures were also screened for cost effectiveness and have been proposed to be included in the expanded DSM Programs.

For example, the Residential Mobile Home New Construction Program was proposed by the Collaborative to be further expanded to include offering incentives to both trade allies and new mobile home buyers to encourage the purchase of high-efficiency central air conditioners versus standard efficiency central air conditioners. Also, an additional measure of programmable thermostat was included in a package of conservation measures offered in the proposed new Modified Energy Fitness Program.

Through continuously monitoring the program performance, program participation level, DSM market potential, and program marketing/delivery mechanisms, the Collaborative has also recommended the deletion and modification of several DSM programs for Kentucky Power. For example, as a result of years of successful program implementation, the potential customer base for Commercial SMART® Audit is exhausted. Hence, the Collaborative recornmended that the Commercial SMART® Audit and SMART® Incentive Programs be discontinued at the end of the year (2002) in the KPCO service territory. The High Efficiency Heat Pump – Single Family Retrofit was discontinued at the end of year 2001 because of the changing economic factors involved and/or the projected decreases in future participation levels. In addition, after examining the alternative delivery mechanisms, a Modified Energy Fitness Program was proposed at the beginning of the year 2003. This program is similar to the old Energy Fitness Program. Modifications to the program include: (1) the addition of a programmable thermostat to the list of energy conservation measures, and (2) the program delivery mechanism was changed from a direct mail brochure to telemarketing services. Also the re-screening and re-evaluation of the Targeted Energy Efficiency (TEE) Program resulted in several changes in the TEE Program to improve its cost-effectiveness. Such continual re-screenings and re-evaluations have resulted in providing DSM programs to KPCO customers in a more efficient and cost-effective manner.

Based on the updated DSM program screening and evaluation, four expanded DSM programs were proposed for KPCO. Exhrbit 3-1 provides a list of these programs, including those proposed by the KPCO DSM Collaborative for continuation and expansion through calendar year in an application filed on August 14,2002 with the Commission. The Commission approved the application on September 24th, 2002. Also included in the list of pragrams are the Commercial SMART® Audit and SMART® Incentive Programs which will be discontinued at the end of 2002, but the impacts are included in the 2002 integrated resource plan. The results of cost-benefit evaluations from the KPCO DSM program screening are shown in Exhrbit 3-2.

The DSM expansion derived from the program-screening analysis served as an input to PROSCREEN/PROVIEW for the 2002 integrated resource analysis. The implementation schedule utilized was based on the current and projected levels of DSM activity in each jurisdiction.

F. IMPACT OF DSM PROGRAMS ON BASE LOAD FORECAST

The estimated total impacts of expanded DSM programs on the projected AEP System and KPCO summer and winter peak demands and annual energy requirements are shown in Exhibit 3-3. These expanded (or incremental) DSM impacts represent the amount by which the base load forecast was reduced in order to determine the resulting adjusted internal demand.

As noted in Exhibit 3-3, at about midway through the forecast period, i.e., the winter of 2010/11, the estimated incremental reduction in the KPCO's base peak internal demand due to the assumed expanded DSM programs is 4 MW, which amounts to 0.3% of peak demand. For the summer of 2010, the corresponding reduction is 2 MW. Similarly, the DSM-related incremental energy reduction in the AEP KPCO's internal energy requirements far the year 2010 amounts to 11 GWh, or 0.1% of those requirements.

The projected DSM impacts indicated in Exhibit 3-2 generally increase in time through about 2006, after which they remain relatively stable until after about 2016, due to the persistence of the DSM savings. Beyond 2016, such impacts decrease, due to the previously-noted assumption that there will be no new DSM conservation program participants after 2005, which would result in no replacements of the DSM measures at the end of their service lives. Thus, by the year 2020, for the AEP System, the total expanded DSM impacts on winter-season demand and annual energy would be reduced to levels of 0 MW and 0 GWh, respectively.

It should be noted that the current KPCO DSM plan, as approved by the Commission, does not extend beyond 2005, although the Company may request future extension of the programs beyond 2005. For the purposes of this report, it was assumed that such planned DSM activity would continue through 2005, at which time the programs would terminate. Details of the original DSM plan may be found in KPCO’s application filed with the Commission on September 27, 1995 and approved by the Commission in an Order dated December 4, 1995 (Case No. 95-427). The current implementation status of each program may be found in the KPCO DSM Collaborative Report filed with the Cornmission on August 14,2002.

G. SIGNIFICANT CHANGES FROM PREVIOUS DSM PLAN

G.l. Screening Methodology

The 1996 DSM screening methodology included a three-stage measure-screening process, plus a two-stage program-screening process. The 1999 DSM screening methodology reduced the number of screening stages by combining both the measure- and program-screening processes. No new additional qualitative analyses of the AEP System DSM programs were conducted since 1996, except for KPCO, through the DSM Collaborative. In 2002, the Company, working with the Collaborative, re-screened the current on-going DSM programs and the expanded programs filed for a three-year extension with the Commission on August 14, 2002. Additional measures were also screened for cost effectiveness and have been included in the proposed expanded DSM Programs. Based on the updated DSM program screening, four expanded residential DSM programs were proposed for KPCO in the 2002 DSM plan. The DSM Collaborative has continued to be the decision-maker on the program-screening process since the initial design and implementation of the KPCO DSM programs.

G.2. Assumptions

The 1996 and 1999 DSM analyses were based on the avoided costs of a combustion turbine, which was assumed to be installed in 2001 and 2005, respectively. The 2002 analysis is based on a 3 Company Regulated Power Pool where the generation capacity requirement will be acquired through purchase on the power market.

G.3. DSM Programs and Impacts

In 1996, KPCO's DSM program development, enhanced through the work of the Collaborative, resulted in six residential DSM programs and two commercial and two industrial DSM programs: Energy Fitness, TEE, Compact Fluorescent Bulb, High-Efficiency Heat Pump, High-Efficiency Heat Pump Mobile Home, Mobile Home New Construction, commercial SMART® Audit, Commercial SMART® Incentive, Industrial SMART® Audit and Industrial SMART® Incentive. In order to continue offering cost-effective energy efficiency and load management options to the Company's customers, and, at the same time, provide programs that are beneficial to customers, the Collaborative decided to discontinue two of the residential programs, Energy Fitness and Compact Fluorescent Bulbs, and the two industrial programs, Industrial SMART® Audit and Industrial SMART® Incentive. Additionally, the Collaborative expanded the residential Mobile Home New Construction Program to full-scale implementation.

In 1999, with the electric utility industry moving forward towards deregulation and restructuring, and with increasing concerns regarding rate impacts, the levels of Company sponsored DSM programs were significantly reduced. In 1999, at a reduced level, KPCO's DSM program development included six residential DSM programs and two commercial DSM programs: Energy Fitness, TEE, High-Efficiency Heat Pump, High-Efficiency Heat Pump Mobile Home, Load Management Water Heating, Mobile Home New Construction, Commercial SMART® Audit and Commercial SMART® Incentive. The Load Management Water Heating Program is not included in the set of KPCO DSM Collaborative programs, but was approved separately under the Load Management Water Heating Provision of the Residential Service Tariff, which became effective April 1, 1997.

The transition from regulated to the unregulated status has already taken place at different stages in the states that AEP serves, and resulted in the recent AEP corporate separation plan and the related Regulated AEP-East System power pool. In 2002, due to these recent developments with respect to deregulation and restructuring in the AEP East System, the Company sponsored DSM programs have further been changed and/or curtailed. The High-Efficiency Heat Pump Program and Load Management Water Heating Program were discontinued in December 2001 in all AEP East service area. With Collaborative approval, the Commercial SMART® Audit and Commercial SMART® Incentive programs will be discontinued in KPCO at the end of calendar year 2002. Exhibit 3-4 provides a comparison of the 1996, 1999 and 2002 plans with respect to the estimated DSM-related load impacts on the AEP System and KPCO for the years 2005, 2010 and 2015. Part of the reduction in the DSM impacts indicated on Exhibit 3-4 for the 1999 and

2002 plans versus the 1996 plan can be attributed to updated estimates of measure persistence, as well as projected lower levels of DSM activity.

H. KPSC STAFF ISSUES ADDRESSED

On June 21, 2000 the Commission issued their Staffs report on KPCO's 1999 Integrated Resource Plan and requested that the Company address certain issues in its next IRP report (this report). The following issues pertaining to DSM are restated from the Staff report and addressed below:

1. Establish an AEP-owned energy service company (ESCO) or form joint ventures with (or purchase) one or more existing ESCos.

As discussed, the emerging competitive environment evolving from restructuring in the electric utility industry and in tlie AEP System, among other factors, has affected the viability of DSM programs. The nature of DSM's role has changed to a supplementary and complementary role in utility resource planning. As the role of DSM programs is changing at this time, AEP does not plan to establish an AEP-owned energy service company (ESCO) or form joint ventures with (or purchase) one or more existing ESCos to promote or expand energy efficiency/DSM programs. Nevertheless, the Company will, as in the past, continue working with existing ESCOs to design and implement DSM programs in the AEP service area to promote energy efficiency at the most efficient way.

2. Use Local Integrated Resource Planning (LIRP)

Integrated Resource Planning assumes that the geographic region (system) to which it is applied is more or less homogeneous with regard to the basic cost arid benefit parameters on which the plan is developed. There are certain circumstances in which this assumption may be less valid. For example, if a reasonably-sized (electrically) load area requires costly local transmission facility reinforcement, the location of supply or demand side resources within that region may be able to defer or offset some portion of the otherwise-required local transmission facilities. This would yield more favorable economic analysis results for such resources when considered for that area than for the aggregate system. Local Integrated Resource Planning (LIRP) is simply an extension of Integrated Resource Planning which takes into account such localized factors, when appropriate.

A review of Kentucky Power system circumstances reveals little opportunity for the successful application of Local Integrated Resource Planning, as opposed to overall system-wide Integrated Resource Planning. There are no instances of cost factors for sizeable load areas which differ substantially fi-om system-wide average values, or where high-cost transmission improvements could be deferred or offset by the addition of local supply side or demand side resources. Furthermore, the size of supply side resources applicable to such applications is generally smaller than the size of resources supported by system-wide planning, falling into a range in which there are definite economies of scale. Any potential savings in deferred / offset transmission facility expansion costs would have to more than offset the diseconomies associated witli the utilization of smaller scale supply side resources.

3. Initiate a Comprehensive program in Commercial New Construction.

Since its inception in May 1996, KPCO and its DSM Collaborative have offered the Smart Audit and Smart Financing Program to new construction customers by auditing the building design plans, identifying energy saving measures, and providing financial incentives for the implementation of reconnnended energy saving measures. As of June 30, 2002, 53 new construction customers have implemented recommended energy saving measures and received a financial incentive. However, almost all of the implemented measures are related to high efficiency HVAC and lighting equipment changeovers, with none performing extensive integrated building analysis to alter the basic new building design. The type of new commercial establishment in KPCO's eastern Kentucky service area (smaller in size compared to national average) and the significant upfront labor and capital requirements needed for developing a new integrated approach to transform the design of new commercial buildings hinder the acceptance and/or applicability of this type of comrnercial new construction program in KPCO's service area.

The type of program proposed by the Kentucky DOE would be more applicable for larger size commercial buildings in a big city environment, and would require the development of long-term relationships with architects, engineering firms, builders, manufacturers, and building supply companies. The technical expertise and the financial requirements to implement this type program could be substantial before any program impacts could be realized. In addition, as summarized by E Source in a report related to promoting an integrated approach to comrnercial new building construction, the cost effectiveness of such a program depends on the type of commercial establishment, the price of electricity in the local area, and other factors. Generally the cost effectiveness of the program will need to be determined on an individual customer basis. Considering the uncertainties about the cost effectiveness of the program, the future regulatory environment, the economy, and the limited applicability to the type of commercial establishments in the KPCO service area, KPCO does not foresee a need to implement a Commercial New Construction Program to assist commercial new building design at this time. The Company believes it would be more effective if such a program would be initiated and fiinded at the state level by a state agency.

4. Promote Cogeneration to Gain Thermal Efficiencies

As approved by the Public Service Commission of Kentucky, KPCO offers two tariffs, COGEN/SPP I and COGEN/SPP II, to customers with cogeneration and/or small power production facilities which qualify under Section 210 of the Public Utility Regulatory Policies Act of 1978. COGEN/SPP I applies to those which have a total design capacity of 100 kW or less; and COGEN/SPP II applies to those which have a total design capacity over 100 kW.

Although there are no KPCO customers currently receiving service under either COGEN/SPP tariff, both are KPCO tariff offerings that are available to customers who want to conduct cogeneration. Because KPCO offers very low electric rates, cogeneration is a less attractive option from an economic standpoint, even when gains in thermal efficiency are included. Cogeneration may be a more viable option if KPCO rates were to increase to the point where it makes cogeneration a serious economic consideration.

5. Promote Distributed Generation and Green Power through net metering.

Distributed generation technology options will continue to develop for customers regardless of whether or not there is net metering. However, promotion of distributed generation and green power through net metering must be reviewed closely in order to avoid the subsidy of such options by the remaining customers of an electric utilty or by the utility.

First, there needs to be an evaluation, determination and agreement of the structure of the net metering rates. In order to properly establish metering provisions, time-differentiated rates for generation service must be included. The cost to produce electricity is valued differently throughout the day. During peak periods, the cost to produce electricity is higher than average. Likewise, during off-peak periods, the cost to produce electricity is lower than average. Therefore, net metering provisions and electricity prices need to reflect these cost variations. It would not be appropriate to offer net metering which provides an average credit/rate throughout the day. Such an approach would allow customers to utilize dispatchable/portable distributed generation (and operate green power production) during KPCO's low-cost, off-peak periods and receive a higher-than-average credit for this off-peak production. Such customer generation during the off-peak period does not benefit the utility generating the power during the high-peak, high-cost on-peak period when electricity is needed the most. Promoting distributed generation and green power through net metering can perhaps be a reality only if there are benefits for all parties involved, and the manner to achieve this is through the use of time-differentiated rates for generation service.

Net metering provisions should never result in a reduction in charges for transmission or distribution service. The existence of distributed generation, which can have some generation value, does not eliminate or reduce the need for proper transmission and distribution facilities to meet the customer's power needs. Any net metering provision which provides credits for transmission or distribution service clearly establishes a subsidy for which there is no basis.

If structured properly to reflect the true costs and benefits of the generation provided through distributed generation and green power, a net metering program would likely achieve no more success than the current COGEN/SPP tariffs. Any non-cost-based incentives implemented to encourage distributed generation and green power for the societal good should not be borne by KPCO.

Over the past several years, AEP has offered Demand-Side Management (DSM) programs developed to encourage efficient use of electricity. However, DSM programs have changed or been curtailed due to new trends in the regulatory and competitive arenas. DSM has shifted from the traditional regulatory perspective to the market-based perspective. This has resulted in reductions in DSM programs within the AEP System. However, KPCO recognizes its responsibility to encourage its customers to make wise use of energy consumption, and therefore it will continue to offer a variety of existing off-peak and interruptible tariffs for customers to achieve energy efficiency and cost savings. These tariffs are also designed to achieve the DSM objectives of peak load shifting, peak clipping and emergency load curtailment.

In place of net metering, the time-of-day and interruptible generation related service options currently in place in KPCO should be encouraged, resulting in generation benefits and lower rates for customers.

Off-Peak service options

KPCO's off-peak rates are designed to encourage customers to shift load from the on-peak period to the off-peak period. Customers participating in these tariffs benefit from lower off-peak rates for energy and demand shifted to or consumed during the off-peak period. Participating customers receive reduced rates and KPCO has the potential to reduce costs and realize efficiency gains in producing electricity.

KPCO offers time-of-day and load management time-of-day provisions to various groups of its customers. The time-of-day provision is generally available for residential customers and provides on-peak and off-peak energy charges. The load management time-of-day provision is available to customers who use energy-storage devices with time-differentiated load characteristics (generally equipment operating only during the off-peak hours).

Interruptible service provisions

KPCO offers Tariff C.S.-I.R.P. for interruptible service, which is essentially another DSM tool that provides industrial and commercial customers a reduced rate in exchange for their agreement to temporarily curtail their service when requested by the Company.

In view of the potential for temporary emergency operating conditions on the AEP System, and to provide additional options for customers, KPCO and other AEP operating companies also have made available Rider Emergency Curtailable Service (ECS). Rider Price Curtailable Service (PCS) is available for curtailments called on an economic basis. These riders are available to commercial and industrial customers who normally take firm service, with demands greater than 1 MW. In the event of curtailments, such customers receive a curtailable credit from the Company, based on the customer's curtailment and the respective pricing provisions of these riders.

The table shown below lists KPCO's tariffs that contain off-peak and interruptible provisions and provides a general description of the tariff.

Tariff Schedule / Provision	Tariff Description
Tariff RS (LM Water Heating Provision) # of customers: 114	Available to residential customers who install a Company-approved load management water-heating system which consumes electrical energy primarily during off-peak hours specified by the Company and stores hot water for use during on-peak hours. This provision provides an off-peak energy charge.
Tariff RS-LMTOD # of customers: 408	Available to customers eligible for Tariff RS (Residential Service) who use energy storage devices with time-differentiated load characteristics approved by the Company which consume electrical energy only during off-peak hours and store energy for use during on-peak hours.
Tariff RS-TOD # of customers: 2	Available for residential electric service through one single-phase multiple-register meter capable of measuring electrical energy consumption during the on-peak and off-peak billing periods to individual residential customers.
Tariff SGS (LMTOD) # of customers: 4 Tariff MGS (LMTOD) # of customers: 118 Tariff LGS (LMTOD) # of customers: 8	Available to customers who use energy-storage devices with time-differentiated load characteristics approved by the Company which consume electrical energy only during off-peak hours specified by the Company and store energy for use during on-peak hours. This tariff provides on-peak and off-peak energy charges.
Tariff MGS-TOD # of customers: 114	Available for general service customers with normal maximum demands greater than 10 kW but less than 100 kW. This tariff provides on-peak and off-peak energy charges.
Tariff QP # of customers: 79	Available for commercial and industrial customers with demands less than 7,500 kW. This tariff provides on-peak and off-peak excess demand charges.

Tariff Schedule	Tariff Description
Tariff CIP - TOD # of customers: 13	Available for commercial and industrial customers with normal maximum demands of 7,500 kW and above. This tariff provides on-peak and off-peak demand charges.
Tariff CS – IRP # of customers: 1	Available to customers operating at subtransmission voltage or higher who contract for service under one of the Company's interruptible service options. The total contract capacity for all customers served under this tariff is limited to 60,000 kW.
Rider ECS (Emergency Curtailable Service) # of customers: 0	Customer's ECS load will be curtailed when an emergency condition exists on the AEP System. Rider ECS is available to customers normally taking firm service under Tariffs QP and CIP – TOD for their total capacity requirements fi-om the Company. The customer must have an on-peak curtailable demand not less than 1 MW and will be compensated for curtailments under the provisions of Rider ECS. Customer selects one of two ECS curtailment options based upon maximum duration and credit amounts. Customer will be subject to curtailment for no more than 50 hours per season.
Rider PCS (Price Curtailable Service) # of customers: 5 within the AEP System; 2 of these 5 are served by KPCO.	Customer's PCS load will be curtailed at the Company's sole discretion. Rider PCS is available to customers normally taking firm service under Tariffs QP and CIP-TOD for their total capacity requirements from the Company. The customer must have an on-peak curtailable demand not less than 1 MW and will be compensated for curtailments under the provisions of Rider PCS. Customer selects one of three PCS curtailment duration options. Customer specifies the maximum number of days during the season that the customer will curtail. The customer also specifies the minimum price at which the customer would curtail. The Company, at its sole discretion, determines whether the customer will be curtailed given the customer's specified PCS curtailment options.

Note 1: Kentucky Power Company off-peak billing period is defined as 9 p.m. to 7 a.m, local time, Monday through Friday including all how-s o f Saturdays and Sundays.

Note 2: The tariff descriptions shown above are in summary form. To obtain a full description, please see the Company's tariff sheets and terms and conditions of service.

6. Support statewide and regional market transformation initiatives

AEP has been active in helping craft the new competitive electricity markets on state, regional and national levels. Following is an outline of some of AEP's initiatives.

Kentucky

Kentucky Energy Policy Advisory Board

The Kentucky Energy Policy Advisory Board was created by executive order by Gov. Paul Patton on May 16,2001. Its primary mandates are to:

- create a statewide energy policy and strategic agenda for the commonwealth;
- study energy markets domestically and internationally to identify energy trends and their potential impact on the state;
- maximize Kentucky's low-cost energy advantage;
- make energy policy that encourages efficient and environmentally responsible use of all energy forms; and
- provide energy policy recommendations to the governor and the General Assembly.

The board has been actively involved in proceedings throughout the summer, helping Gov. Patton prepare for the introduction of energy legislation during the 30-day 2003 legislative session.

The board sponsors five subcommittees: Coal Industry, Natural Gas and Petroleum Industry, Electric Industry, Nuclear Industry and Energy Efficiency and Alternative Energy. AEP is represented on most subcommittees (except Nuclear Industry and Natural Gas and Petroleum Industry, neither of which AEP is involved in the state of Kentucky.) AEP representatives on the subcommittees include:

- *Coal Industry:* Timothy C. Mosher, AEP Kentucky State President (subcommittee co-chair)
- *Electric Industry*: Mark A. Bailey, Vice President – Transmission Asset Management; Gregory G. Pauley, Kentucky Governmental Affairs Manager, and Errol R. Wagner, Director – Regulatory Services
- *Energy Efficiency and Alternative Energy:* Guy Cerimele, Kentucky Environmental Affairs Manager.

Governor's Energy Summit

AEP supported Governor Paul Patton's Energy Summit, which began October 9,2002 in Louisville. The Summit was designed to help Kentucky state officials and business leaders address the issues of the Federal Energy Regulatory Commission's Standard

Market Design Notice of Proposed Rulemaking, a 600-page document designed to establish a single set of electricity market rules for the entire country.

The Smnmit was timed to be beneficial to any interested parties intending to file comments with the FERC by the first filing deadline, November 15, 2002.

Regional

Regional Transmission Organization Development

AEP has been a national leader in development of Regional Transmission Organizations. Having fully explored all options for AEP's eastern territories, AEP has chosen to affiliate with PJM Interconnection, LLC. This RTO selection has been conditionally approved by FERC.

RTOs, although regional in scope, are a major component of FERC's Standard Market Design proposed rulemaking. While AEP is joining PJM and other Kentucky electric utilities are joining MTSO, and MISO is pursuing a merger with the Southwest Power Pool, the cooperative arrangements between PJM and MISO ultimately mean Kentucky will be part of a single energy market that stretches from West Texas to New Jersey and from Louisiana to Ontario. The PJM-MISO/SPP agreement, coupled with the FERC's SMD, will mean seamless service in the state of Kentucky with opportunities for Kentucky to reach beyond its borders into broad energy markets.

National

Standard Market Design Activities

AEP has participated in many FERC meetings and technical conferences, made presentations to FERC and filed comments with the agency regarding the concept of Standard Market Design. Following numerous opportunities for public input, FERC issued its SMD proposed rulemaking in late July, with comments on the rulemaking due beginning November 15. AEP is actively reviewing the NOPR and will file comments.

Current Legislation

In 2001, the U.S. House of Representatives passed energy legislation, although it did not contain an electricity title. In 2002, the Senate passed its own energy bill, which did contain an electricity title. Currently, the legislation is in conference committee. House Energy and Commerce Committee chair Billy Tauzin (R-La.) is chairing that effort. Although the committee still is striving to move a bill before Congress adjourns for the November elections, skeptics predict it may not happen in 2002.

AEP is closely monitoring the evolution of both House and Senate energy bills.

Exhibit 3-1

KPCO and Regulated AEP East System
Expanded DSM Programs

Residential Programs:

1. Targeted Energy Efficiency **(Low-Income** Weatherization)
2. Modified Energy Fitness
3. High-Efficiency Heat Pump Mobile Home
4. Mobile Home New Construction

Commercial Programs:

SMART Audit/Incentive

Note: (a) For KPCO, the-Residential Modified Energy Fitness Program will be [illegible] in [illegible] 2003, with Com[illegible] i [illegible] i [illegible] pp [illegible] l

(b) For KPCO, tl[illegible] Commercial SMART Audit/Incentive Programs will be discontinued at year-end 2002, with Collaborative approval.

Exhibit 3-2

KPCO

2002 DSM Program Screening Summary – Cost/Benefit Evaluation

	TRC B/C Ratio	RIM B/C Ratio	uc B/C Ratio	P B/C Ratia
Residential Programs:				
1. Targeted Energy Efficiency	0.57	0.31	0.57	n/a
2. Modified Energy Fitness	1.43	0.49	1.49	n/a
3. High-Efficiency Heat Pump Mobile Home	1.69	0.43	1.11	3.63
4. Mobile Home New Construction	1.03	0.50	1.50	2.14
Commercial Programs:				
1. SMART Incentive	2.04	*0.55* -	3.01	6.11

Note: (a) Cost/Benefit Evaluation based on projected program participation level between 2002 to 2005.

(b) Residential Modified Energy Fitness Program will be implemented in January 2003, with Commission approval.

(c) Commercial SMART Incentive Programs will be discontinued at year-end 2002, with Collaborative approval.

Exhibit 3-3

KPCO and Regulated AEP-East System
Estimated Load Impacts of Expanded DSM Programs
2002 - 2020

	KPCO			Regulated AEP East System		
	Demand Reduction			Demand Reduction		
Year	Summer (MW)	Winter Following (MW)	Energy Reduction (GWh)	Summer (MW)	Winter Following (MW)	Energy Reduction (GWh)
2002	0	1	2	0	1	2
2003	1	2	5	1	2	5
2004	1	3	7	1	3	7
2005	1	4	10	1	4	10
2006	2	4	11	2	4	11
2007	2	4	11	2	4	11
2008	2	4	11	2	4	11
2009	2	4	11	2	4	11
2010	2	4	11	2	4	11
2011	2	4	11	2	4	11
2012	2	4	11	2	4	11
2013	2	4	11	2	4	11
2014	2	4	11	2	4	11
2015	2	4	11	2	4	11
2016	2	4	11	2	4	11
2017	1	3	9	1	3	9
2018	1	2	6	1	2	6
2019	1	0	4	1	0	4
2020	0	0	0	0	0	0
2021	0	0	0	0	0	0

Note: Expanded DSM program impacts result from installations assumed to be ma in the future and are not reflected in the base load forecast Impacts of DSM program installations already in-place, i.e., embedded DSM program impacts, are reflected in

Exhibit 3-4
KPCO and AEP East System
Estimated Reduction in Forecasted
Energy Requirements and Peak Demand
Due to Expanded DSM Programs
For Years 2005,2010 and 2015

Comparison of 1996,1999 and 2002 Plans

	AEP East System			KPCO		
Reduction in Energy Requirements (GWh)	1996 Plan	1999 Plan	2002 Plan	1996 Plan	1999 Plan	2002 Plan
2005	202	69	21	71	7	10
2010	174	68	24	56	7	11
2015	96	53	21	35	5	11
Reduction in Winter Peak Demand (MW)						
2005106	321	61	7	42	5	4
2010/11	315	60	7	39	5	4
2015/16	240	40	6	27	3	4

Note that AEP East System included all AEP wholly owned regulated and unregulated operating companies in the AEP East service area.

4. RESOURCE FORECAST

4. RESOURCE FORECAST

A. RESOURCE PLANNING OBJECTIVES

The primary objective of power system planning is to assure the reliable, adequate and economical supply of electric power and energy to the consumer, in an environmentally compatible manner. Implicit in this primary objective are related objectives, which include, in part: (1) maximizing the efficiency of operation of the power supply system, and (2) encouraging the wise and efficient use of energy.

In the planning of power supply resources for the AEP System, consideration is given to several broad factors, including: (1) reliability, i.e., the ability of the system (with recognition of support available from the adjacent region) to provide continuous electric service not only under normal conditions, but also during various contingency conditions, (2) economy, so as to minimize the cost of power supply on a long-term basis, (3) environmental compatibility, (4) financial requirements, and (5) flexibility, i.e., the extent to which plans for future resources can be adjusted to meet changing conditions.

B. KPCO/AEP SYSTEM RESOURCE PLANNING CONSIDERATIONS

B.1. General

Major structural changes are taking place in the electric utility industry. Among these is a transition away from the integrated utility generation, transmission, and distribution structure. This system is being replaced by a combination of regional transmission organizations that will have responsibility for planning and operation of the transmission system, along with a generating system that includes both utility and independent generating capacity. Along with this structure a market for generation products is developing, with the major "product" at present (in the ECAR region) being energy. Simultaneously, the State of Ohio has deregulated generation, mandated corporate separation, and eliminated the concept of native load retail service in favor of competition at retail. This has necessitated the proposal of a modified AEP generation interconnection agreement that will exclude from the AEP-East System the Ohio operating companies, CSP and OPCO. The Restated and Amended Interconnection Agreement among APCo, I&M, KPCO, and the AEP Service Corporation was approved by the FERC on September 26,2002. This agreement will not become effective until after SEC approval. These three operating companies form the Regulated AEP-East System which is planned and operated as a completely integrated electric power system. Although the generation interconnection agreement consists of the three noted companies, AEP transmission operating and planning continues to be performed on an integrated basis for the seven eastern operating companies.

The AEP System plans to purchase capacity and/or energy from the developing market to provide adequate daily operating reserves. ECAR at present requires a reserve of 4% of the projected daily peak load. AEP has obtained conditional approval from FERC to join PJM as it's RTO selection for AEP's eastern region companies, which includes KPCO. AEP will become a member of PJM and transfer functional control of it's transmission facilities to PJM for inclusion in an expanded PJM-West Region. Additionally, the AEP control area functions will be integrated into the PJM Interchange Energy Market and certain other PJM markets during the first half of 2003. AEP's integration into PJM may require changes in certain operations and planning processes and requirements to ensure reliable and efficient operations of transmission and energy markets within PJM.

The Regulated AEP-East System is planned, constructed and operated as an integrated power system. It is necessary to establish and maintain sufficient generating-capacity resources to assure a reliable bulk power supply to the aggregate load of the combined operating companies. However, each operating subsidiary is still responsible for providing adequate generating-capacity resources to supply its own requirements. Under the Restated and Amended Interconnection Agreement (which represents the "pool agreement" among the three regulated, major AEP operating companies), each member of the pool is responsible for a proportionate share of the aggregate AEP pool generating capacity. Each member must provide sufficient generating capacity to meet its own internal load requirements plus an adequate reserve margin. Whenever a member company's generating capability is insufficient to supply its demand, it draws upon the resources of the other AEP companies in accordance with the provisions of the Interconnection Agreement. At other times that company may have generating capability in excess of its own needs, which is utilized as necessary to supply part of the load requirements of the other AEP companies.

Thus, the evaluation of the adequacy and reliability of KPCO's generating capability to meet the current and projected power demands of its customers must be based on consideration of the total generating capability of the Regulated AEP-East System in relation to the aggregate Regulated AEP-East System load (taking into account contractual arrangements with other affiliated and nonaffiliated parties and the availability of power from other regional sources).

KPCO's Big Sandy generating plant is centrally dispatched in conjunction with the plants of other Regulated AEP-East System operating companies from the AEP System Control Center located in Columbus, Ohio. This process of dispatching all of the system's generating units from one control center enables the AEP System to continuously supply power in the most reliable and economical manner to all of its customers from the combined generating capacity of the Regulated AEP-East System.

The System's major operating companies are electrically connected by a high capacity transmission system extending from Virginia to Michigan. This transmission system, composed of a 765-kV, 500-kV, 345-kV, and 230-kV extra-high-voltage network, together with an extensive underlying 138-kV transmission network, is planned, constructed, and operated to provide a reliable mechanism to transmit the electrical output from AEP generating plants to the principal load centers. In addition, this transmission network is interconnected with 29 neighboring electric systems by 144 interconnections at or above 115 kV.

Exhibit 4-1 displays a map of KPCO's transmission system, showing the location of KPCO's generating plant. Exhibit 4-2 provides a similar map for the entire eastern AEP Transmission System. Exhibit 4-3 lists the AEP interconnections in the Kentucky area.

B.2. Development of Generation Reliability Criterion Guideline

With regard to reserve planning, the ultimate objective of reserve planning is to ensure that adequate operating reserves will be available at all times. (Operating reserve provides for contingencies such as load forecast errors arid unplanned generating unit outages, as well as, load following and frequency control.) In the old, "single system" planning model, each utility system had to ensure that its own dedicated resources would be adequate to provide such operating reserve. This was accomplished through the provision of long-term "planning reserves," which provided coverage for both forced and scheduled outages of generating units, unexpected system load growth, etc. Individual system resources were then added as appropriate to provide adequate "planning reserves."

With the emergence of substantial non-utility generation resource additions to provide resources to the regional market, the focus of utility resource planning has changed. Each system must still provide adequate operating reserves, but "planning reserves" must now be assessed on a regional, rather than an individual system, basis. Thus, as long as regional resources are adequate, an individual system planning reserve, if any, reflecting dedicated supply-side resources, are a lesser indicator of long-term system reliability.

B.2.a. Definition of Reliability

Generation system reliability (i.e., generation reserve adequacy) may be defined as the degree to which the system is able to supply the power requirements of its customers, on demand, during both normal and abnormal conditions. Generation system reliability may be expressed or measured in different ways, such as by the frequency, duration and magnitude of capacity shortfalls. From a planning perspective, the expected reliability performance level of a given generation system over a given period of time provides a measure af the ability—or, conversely, the inability—of that system to meet its load requirements continuously throughout that time period. Generation system reliability performance indices provide an indication of potential future resource requirements.

B.2.b. Reliability Indices

Reliability indices are typically categorized as either deterministic or probabilistic. Deterministic indices are relatively simple measures, e.g., installed capacity reserve expressed either as a percentage of peak load or in terms of the extent of coverage of the system's largest generating units. Probabilistic indices, on the other hand, are computed using relatively complex mathematical models that typically convolve load and capacity distributions to determine the expected amounts of time that available generating capability is insufficient to serve load. In view of the relative advantages and disadvantages of both types of indices, many utilities, including AEP, use both deterministic and probabilistic indices in their reliability assessments in order to provide multiple perspectives in the evaluation of power supply reliability.

B.2.c. Need for Adequate Reserves

Reserve margin is that portion of the capacity resources which exceeds peak demand. Continuity of supply cannot be assured unless the utility has not only enough generating resources to supply its customers' peak demands, but also an additional amount of reserve margin to provide for contingencies.

In the near-term, reserve margins provide a utility with flexibility and a margin of safety for daily operation. Reserve margins are needed in daily system operation because the utility must keep an amount of operating, but unloaded, capacity on line to maintain scheduled power flows on tie lines and to permit satisfactory regulation of system frequency. Reserve margins also provide protection against combinations of contingencies, whose total magnitude is both variable and uncertain. Those contingencies include, but are not limited to, the following:

- generating unit forced outages;
- reductions in generating unit capability due to equipment failures or adverse operating conditions;
- reductions in electrical output due to transmission restrictions;
- reductions in generating unit capability (or even shutdowns of units) due to environmental constraints or actions by regulatory authorities; and
- load increases due to extreme weather conditions.

On a long-term basis, in addition to the factors mentioned above, reserve margins are needed to provide for unanticipated increases in electricity demand growth, delays in commercial operation of scheduled generating unit additions, and unanticipated regulatory or legislative actions.

R.2.d. AEP's Capacity Reserve Analysis Program

The basic concepts described above for evaluating a power system's installed reserves are embodied in AEP's Capacity Reserve Analysis (CRA) computer program. This program, which simulates the operation of the power system for each hour of the study period, calculates the range of daily capacity margins -- and the associated reliability performance level -- likely to occur throughout the study period, based on the relationships between: (I) a capacity model that reflects, for each hour, scheduled outages and seasonal deratings of generating units in a deterministic fashion, as well as full and partial forced outages in a random or probabilistic fashion, and (2) an hourly load model for the study year. More specifically, for a given study year, the program performs the following steps:

1. Determines for each week in the year a load-duration curve for:
   a. the weekday daily peak hours;
   b. the on-peak period hours; and
   c. the off-peak period hours;

2. Calculates, for each week, on- and off-peak period probability distributions of available system capacity, considering scheduled maintenance, seasonal ratings, and forced and partial outage rates;

3. Mathematically convolves the capacity distributions with the corresponding load-duration curves, with proper adjustments made for firm or committed sales and purchases with neighboring power systems, to determine probability distributions of capacity margins; and

4. Sums the resulting distributions of capacity margins for each week and for the entire year, to produce weekly and annual statistics for the daily peaks, on-peak periods, and all hours.

B.2.e. Reliability Criterion Guideline

The Regulated AEP-East System plans to have sufficient capacity to provide adequate daily operating reserves. ECAR at present requires a reserve of 4% of the projected daily peak load.

For reporting purposes in the forecast period, the CRA program was used to calculate the amount of capacity for the Regulated AEP-East System at the time of its winter and summer peak demands needed to operate with an expected deficiency (i.e., shortage of operating reserves) of 0.5 day per week. (The 0.5 day per week level is reasonable both (1) in that a higher figure would imply that a shortage would be expected and (2) in comparison with the 20 to 40 capacity deficient days expectation used by the AEP System in previous years under more traditional planning regimes). The result of this study was a planning guideline that a 12% reserve margin at time of seasonal peak demand would provide an adequate level of reliability. (In addition, the recent FERC NOPR regarding Standard Market Design is recommending that utilities maintain a minimum 12% reserve margin.)

The incremental capacity needed to maintain this margin is indicated as "uncommitted purchases" in Exhibits 4-11 and 4-12. These amounts do not represent a rigid forecast of required purchases or a plan for the reservation of such amounts.

C. PROCEDURE TO FORMULATE LONG-TERM PLAN

The following steps were involved to develop the resource plan presented in this report. These steps are as follows:

1. Development of the base-case load forecast.

2. Determination of overall resource requirements.
3. Impact of Integrated Resources
   a. Determination of impact of DSM programs on base-case load forecast.
   b. Development of supply-side resource expansion with expanded DSM.

4. Analysis and Review.

A discussion of these steps follows.

C.1. Development of Base-Case Load Forecast

The development of the base-case load forecast is presented in Chapter 2. That initial forecast excludes adjustments for potential future (i.e., expanded) DSM programs.

C.2. Determination of Overall Resource Requirements

The determination of overall resource requirements includes an evaluation of the adequacy of existing generating capability to meet the future forecasted load requirements. These items are discussed below.

C.2.a. Existing Generation Facilities

As noted on Exhibit 4-4, KPCO's existing installed generating capability (as of January 1, 2002) is 1,060 MW, which consists of the Big Sandy generating plant, located in Louisa, Kentucky. KPCO also has a unit power agreement with AEP Generating Company (AEG), an affiliate, to purchase 195 MW of capacity from each of the two units at the Rockport Plant, located in southern Indiana. In Case Nos. ER01-2668 and EC01-130 the Company reached a settlement with all parties with respect to the extension of the Rockport Unit Power Agreements. The Rockport Unit No. 1 Unit Power Agreement was extended from December 31, 2004 through December 31, 2009. The Rockport Unit No. 2 Unit Power Agreement was extended from December 31,2004 through December 7,2022 or the end of the lease agreement.

In comparison, the Regulated AEP-East System's total generating capability is 12,171 MW (11,921 MW, after adjusting for 250 MW of unit power sales). The generating facilities which cornprose this capability are listed in Exhibit 4-5.

Actual production cost and operating information for each of the System's steam generating plants for the year 2001 is provided in Exhibit 4-6.

C.2.b. Demands, Capabilities and Reserve Margins Assuming No New Resources

Exhibits 4-7 and 4-8 provide a projection of the Regulated AEP-East System's peak demands, capabilities and reserve margins for the summer and winter seasons, respectively, from 2002 through 2016, assuming no new resources are added to the system. Data for the year 2002 are provided on a "status quo" five-company AEP East System basis. The remainder of the forecast period reflects corporate separation; and, as such, is provided on a three-member Regulated AEP-East basis. The projected data reflect the base-case load forecast, committed sales to non-affiliated utilities, and the amount of AEP's industrial interruptible load that can be interrupted at the time of the seasonal peak. The projected capabilities assume no retirements of existing generating units and excludes the 250 MW currently committed to be sold via a unit power sale from Rockport to Carolina Power & Light.

The corresponding projections of KPCO's peak demands, capabilities and reserve margins are shown on Exhibits 4-9 and 4-10 for the summer and winter seasons, respectively.

C.2.c. Retrofit or Life Extension of Existing Facilities

Past experience has indicated that, with proper maintenance and operation, coal-fired units can expect to achieve operating lifetimes beyond the traditional nominal 35 to 40 years. Of course, the achievable lifetime is highly unit-specific. Programs have been developed by AEP to attempt to achieve optimal operating lifetimes, and to do so as economically as possible. The work of component refurbishment or replacement is planned and carried out over a long period, so as to minimize total cost and the outage time required.

C.2.d. External Resource Options

C.2.d.l. Purchased Power

AEP currently is planning to meet its incremental capacity needs in the short term by purchasing capacity and/or energy from the market, as long as market supplies are adequate and economical.

In the long term, needs will be met by purchases, by construction of new capacity, or by a combination thereof, dependent on the economics of each alternative.

Regarding the availability of capacity to be purchased from the market, significant capacity additions have been announced in the ECAR region, of which AEP is a member. The recently issued *Assessment of ECAR-Wide Capacity Margins 2002-2011* indicates that 41,615 MW of new capacity have been announced for installation within the region for the years 2003 through 2007. The study and report estimates that if only 8,734 MW of this new capacity is in service by the year 2006, adequate reliability levels will be maintained. If the announced additions were to be installed (some will most likely be delayed or cancelled) and the peak demand growth projections are accurate, ECAR could see a rise in reserve margins to about 32% by 2005.

C.2.d.2. Non-Utility Generation

Non-utility generation as a resource option is evaluated as resource needs and specific opportunities arise and pertinent information becomes available before any final decision and commitments are made for specific resources.

Currently, approximately 3,500 MW of Independent Power Producers /Non-Utility Generator (IPP/NUG) capacity is connected to the eastern AEP transmission system. Approximately 15,000 MW of additional IPP/NUG is planned to be connected to the eastern AEP transmission system over the next five years. However, based on the current economic situation a significant number of the planned facilites will likely be delayed and some ultimately canceled. AEP has committed to purchase power, through Appalachian Power Company, from Summersville Hydro, a PURPA Qualifying Facility (QF). Expected power purchase levels from this QF are 24 MW and 16 MW for the winter and summer seasons, respectively.

C.3. Impact of Integrated Resources

C.3.a. Determination of Impact of DSM Programs on Base-Case Load Forecast

The DSM-program impacts reflected in the integration analysis are discussed in Chapter 3.

C.3.b. Development of Supply-side Resource Expansion with DSM

Exhibits 4-11 and 4-12 show the current supply-side resource expansion plan with expanded DSM, along with the corresponding projected AEP System peak demands, capabilities, and margins, for the summer and winter seasons, respectively, after adjusting the demands for DSM impacts. The resource expansion is portrayed as uncommitted purchased capacity based on maintaining the target reserve margin of 12%.

In a broad sense, the capacity expansion portrayed on Exhibits 4-11 and 4-12 provides an indicator of the timing and amounts of new resources that may be required to serve the Regulated AEP-East System's future loads in a reliable manner. If the regional power market tightens, and resource commitments must be made, all options will be considered, including both self-build and external resource options.

Exhibits 4-13 and 4-14 show KPCO's corresponding projected summer and winter peak demands, capabilities, and reserve margins for the forecast period, after adjusting the demands for DSM impacts, and allocating the AEP System resource additions shown on Exhibits 4-11 and 4-12 to the three Regulated AEP-East operating companies. To allocate such resource additions equitably, they are generally assigned to the operating company with the lowest reserve margin.

Exhibit 4-15 provides projected annual energy requirements, energy resources and energy inputs by primary fuel type.

C.4. Analysis and Review

The AEP System integrated resource plan presented herein is expected to provide adequate reliability over the forecast period.

The long-term capacity schedule reported herein is simply a snapshot of the future at this time, based on current thinking relative to various parameters, each having its own degree of uncertainty. The expansion reflects, to a large extent, assumptions that are subject to change. Other parameters that will affect future outcomes are the impact of competition and the continuing impact of open-access transmission. As the future unfolds, and as parameter changes are recognized and updated, input information must be continually evaluated, and resource plans modified as appropriate.

Some key factors that can affect the timing of future capacity additions are the magnitude of future loads and capacity reserve requirements. The magnitude of the future load in any particular year is a function of load growth and DSM impacts. Capacity reserve requirements, as discussed previously in this chapter, could vary depending on the desired reliability level and average system generating-unit availability.

Exhibit 4-16 provides a comparison of the previously reported (1999) plan for the five-company AEP East System and the current (2002) plan for the three company Regulated AEP-East System. The exhibit shows that for the 2002 plan, for KPCO, through the year 2017, a total of 870 MW of capacity is assumed to be purchased. In comparison, the 1999 plan shows a total of 1,000 MW for the same time frame.

D. OTHER CONSIDERATIONS AND ISSUES

D.l. Transmission System

The AEP System's strong transmission network and its strong intercormections with neighboring utilities are of great value to each of the AEP operating companies in terms of reliability and increased flexibility of operation. AEP and its operating companies continually review the need for reinforcement (i.e., improvements) to their transmission (and distribution) facilities, in order to maintain an acceptable level of reliability and flexibility of operation.

The System's major operating companies are electrically connected by a high capacity transmission system extending from Virginia to Michigan. This transmission system, composed of a 765-kV, 500-kV, 345-kV, and 230-kV extra-high-voltage network, together with an extensive underlying 138-kV transmission network, is planned, constructed, and operated to provide a reliable mechanism to transmit the electrical output from AEP generating plants to the principal load centers. In addition, this transmission network is interconnected with 29 neighboring electric systems by 144 interconnections at or above 115 kV.

The AEP System's ability to meet its customers' future electric needs will be affected by the timely completion of planned transmission reinforcement projects, including the Wyoming-Jackson Ferry 765-kV Project. AEP continues to seek approval of this project.

In the case of KPCO, a major transmission construction program was completed in 1999 to accommodate load growth. This program included the upgrading and reinforcement of the transmission system in the Inez and Tri-state areas of eastern Kentucky. The principal project in this program was the Big Sandy/Inez project, which included the construction of approximately 53 miles of 138-kV transmission lines (33 miles from the Big Sandy Station to the Inez Station, and 20 miles from the Inez Station to the Johns Creek Station), and the installation of associated facilities at those stations.

Among the new facilities installed was a 600-MVA, 345/138-kV transformer at the Big Sandy Station; and, at the Inez Station, a Unified Power Flow Controller (UPFC), a device that incorporates solid-state electronic technology for controlling power line flows and voltages. The major components of that UPFC device are a ±160-MVAr shunt inverter/static comperisator on the Inez Station's 138-kV bus, and a ±160-MVAr series inverter on the Big Sandy-Inez 138-kV line.

It is noted that, as part of the planning process, AEP and its operating companies continually explore opportunities for improving the efficiency of utilization of their power supply facilities, and actions are taken as appropriate (as, for example, in the case of transmission reinforcement plans). In this regard, opportunities for reductions in system losses is a major consideration in the planning of such facilities. Reduction in these losses represents, in effect, conservation of energy resources on the "utility side" of the meter. For example, the Big Sandy – Inez project resulted in a reduction in the area losses)at peak load) of about 24 MW.

In general, losses on the AEP transmission system have been reduced over time as a result of the development of progressively higher transmission voltage levels, the selection of equipment with lower losses (such as larger sizes of conductors), and modifications to network topology, i.e., transmission-line reconfigurations and additions. Similarly, losses on the distribution system have been reduced as a result of conversions to higher voltage levels, other network modifications, and selection of equipment options with consideration for losses.

D.2. Fuel Adequacy and Procurement

D.2.a. Coal

The generating units of Regulated AEP-East, which are predominantly coal-fired, are expected to have adequate fuel supplies to meet normal burn requirements in both the short-term and the long-term. KPCO and the other Regulated AEP-East operating companies attempt to maintain in storage at each plant an adequate coal supply to meet normal bum requirements. However, in situations where coal supplies fall below prescribed minimum levels, Regulated AEP-East companies have developed programs to conserve coal supplies. These programs involve, on a progressive basis, limitations on sales of power and energy to neighboring utilities, appeals to customers for voluntary limitations of electric usage to essential needs, curtailment of sales to certain industrial customers, voltage reductions and, finally, mandatory reductions of usage of electricity. In the event of a potential severe coal shortage, the Regulated AEP-East's operating companies, including KPCO, will implement procedures for the orderly reduction of the consumption of electricity, in accordance with the AEP Eastern System Emergency Operating Plan, which has been filed with each of the appropriate regulatory authorities, including the Kentucky Public Service Commission.

American Electric Power Service Corporation, acting as agent for each of Regulated AEP-East's generating companies, is responsible for the overall procurement and delivery of coal to all of Regulated AEP-East's generating facilities. Regulated AEP-East obtains much of its total coal requirements under long-term arrangements, thus assuring the plants of a relatively stable and consistent supply of coal. The remaining coal requirements are normally satisfied by making short-term and spot-market purchases. Additional spot purchases may occasionally be necessitated by shortfalls in deliveries caused by force majeure and other unforeseeable or unexpected circumstances. Occasionally, spot purchases may also be made to test-bum any promising and potential new long-term sources of coal in order to determine their acceptability as a fuel source in a given power plant's generating units. This policy also provides some flexibility to adjust scheduled contract deliveries for short-term coal supply to accommodate changing demand, which may be more or less than anticipated when the long-term coal requirements were initially projected. During periods preceding the expiration of coal mining labor agreements, additional fuel is stockpiled at Regulated AEP-East's power plants to assure ˊ. adequate supplies in the event of prolonged actions.

Regulated AEP-East's fuel requirements vary from plant to plant, depending upon such factors as environmental restrictions arid boiler design, as well as the demand for electricity. In 2001, coal consumption at Regulated AEP-East operated plants aggregated to more than 28 million tons. Of this amount, KPCO's Big Sandy plant accounted for about 3 million tons. Historically, the coal supplies for the Big Sandy plant have primarily been provided by operations located in Kentucky.

D.2.b. Natural Gas

It is anticipated that the site(s) for any new gas-fired capacity that might be added to the Regulated AEP-East would be determined by analyzing both the Regulated AEP-East infrastructure capabilities and the availability/proximity of mainline gas transmission pipelines. These pipelines would act as transporters for natural gas which would be purchased from third parties. Through the integrated natural gas transmission network, gas could be sourced from all major production areas, including Appalachia, Canada, Louisiana, Offshore-Gulf of Mexico, Oklahoma, and Texas. It is anticipated that distillate oil would be the backup fuel for any new gas-fired capacity; hence, on-site oil storage would be considered for these potential unit sites.

D.3. Environmental Compliance

The AEP System's strategy for continuing to meet the Title IV air emission requirements of the Clean Air Act Amendments of 1990, taking into consideration the inception of Phase II of those requirements in the year 2000, includes the continual evaluation of alternative fuel strategies, opportunities to purchase sulfur dioxide (SO2) allowances, and possible post-combustion technologies in order to lower the overall cost-impact of compliance. AEP's plan anticipates the continued use of low-sulfur coal over most of the AEP System, the use of the Phase I accumulated SO2 allowance bank, supplementing the allowance bank and the switching to lower-sulfur fiiels when economical.

The AEP System will also be required to meet more stringent NOx emission limitations during the May through September ozone season beginning in May 2004. These requirements will include Big Sandy Plant in Kentucky. The compliance plan for Big Sandy Plant to meet this requirement includes installation of an overfire air burner modification and water injection system and boiler tubes overlay on Unit 1 and installation of a selective catalytic reduction (SCR) system on Unit 2. The latter installation also requires an upgrading of the Unit 2 electrostatic precipitator. Similar NOx reduction technologies will be implemented at other units across the AEP System.

On September 30, 2002 the Company filed with the Commission revisions to the Company's Environmental Compliance Plan at the Big Sandy Generating Plant as described above, and an application to recover the associated costs by way of the Environmental Surcharge.

The Integrated Resource Plan (IRP) is based on current mandatory environmental requirements (the existing SO2 reduction program under the CAAA of 1990 and the NOx SIP Call requirements for seasonal NOx reductions in the Midwestern U.S.). However, the IRP does not include the potential impacts of new air emission regulations or air emission legislation (so called 3P and 4P legislation) aimed at further significant reductions in SO2, NOx, mercury and in the case of 4P legislation C02 emission reductions. While it is quite possible that there may be new legislation and/or new regulations governing these pollutants in the future, it is very difficult to predict future legislative and regulatory outcomes. In addition, the EPA is scheduled to propose a Mercury MACT (maximum achievable control technology) standand during 2003. However, it is uncertain the degree of reductions or type of mercury standard likely to be proposed at ths time.

E. RESOURCE PLANNING MODELS

Information which describes the planning models (apart from the load forecasting models) utilized by AEP in developing its integrated resource plans is provided below.

E.l. Capacity Reserve Analysis (CRA) Model

The Capacity Reserve Analysis (CRA) Model program is described in detail in Section B.2.d. of this chapter.

E.2. PROMQD

PROMOD is a computer program that simulates how an electric utility operates and dispatches its generating units. Inputs to PROMOD include: forecasted loads and load shapes; forecasted price and availability of fuel; prices and quantities for capacity and energy purchases and sales; capacities, availabilities and heat rates for generating units; and data that describe rules for committing and dispatching generating units. PROMOD's outputs include: generation by unit; fuel consumption and fuel expense by unit and by fuel contract; and purchases and sales of energy and their associated casts and revenues.

PROMOD simulates the operation of an electric utility system by economically dispatching the utility's generating resources subject to various operating constraints such as fuel supply limitations, the need to maintain operating reserves, minimum operating and shutdown intervals for generating units and power transfer constraints. PROMOD explicitly recognizes the effect of generating unit forced outages and their impact on system operating costs.

E.3. DSM Screening Model

The DSM screening model used in the screening process for both DSM measures and DSM programs is described in Chapter 3. The model, which was developed in-house, performs various economic calculations, assessing the benefits and costs of each DSM measure or program, based on the Total Resource Cost, Ratepayer Impact Measure, Participant Cost and Utility Cost tests. The software provides the flexibility to incorporate various parameters arid input data assumptions for each DSM measure individually, as well as for each DSM program.

F. KPSC STAFF ISSUES ADDRESSED

On June 21,2000 the Commission issued their Staffs report on KPCO's 1999 Integrated Resource Plan and requested that the Company address certain issues in its next IRP report (this report). The following recommendations pertaining to Supply-side Resource Assessment are restated from the Staff report and addressed below:

1. Kentucky Power/AEP should continue to expand the list of options screened.

   As discussed in Section B.2.e. due to the current abundance of capacity in the ECAR region, there are adequate capacity resources available without additional Company built resources. At this time, the Company believes it is prudent to buy from the market rather than build capacity.

2. Kentucky Power/AEP should screen purchased power in the same manner as other supply-side alternatives.

   As discussed above, KPCO/AEP will rely on the market to purchase its power needs in the short term as long as the market supplies are adequate and economical. In the long-term, needs will be met by purchases, by construction of new capacity, or by a combination thereof, dependent on the economics of each alternative.

3. Kentucky Power/AEP should fully consider the potential effects of environmental considerations, especially NOx requirements and **CO2** concerns, in its supply-side analysis and should thoroughly document its analysis of these issues.

   AEP's environmental compliance is discussed in Section D.3.

4. While the methodology is sound, the results are limited by the shortcomings in Kentucky Power/AEP's supply-side analysis. Staff recommends that Kentucky Power/AEP follow the same integration methodology in its next IRP, but with a broader view of supply-side options including potential environmental costs.

   See the responses to the above Items 1-3.

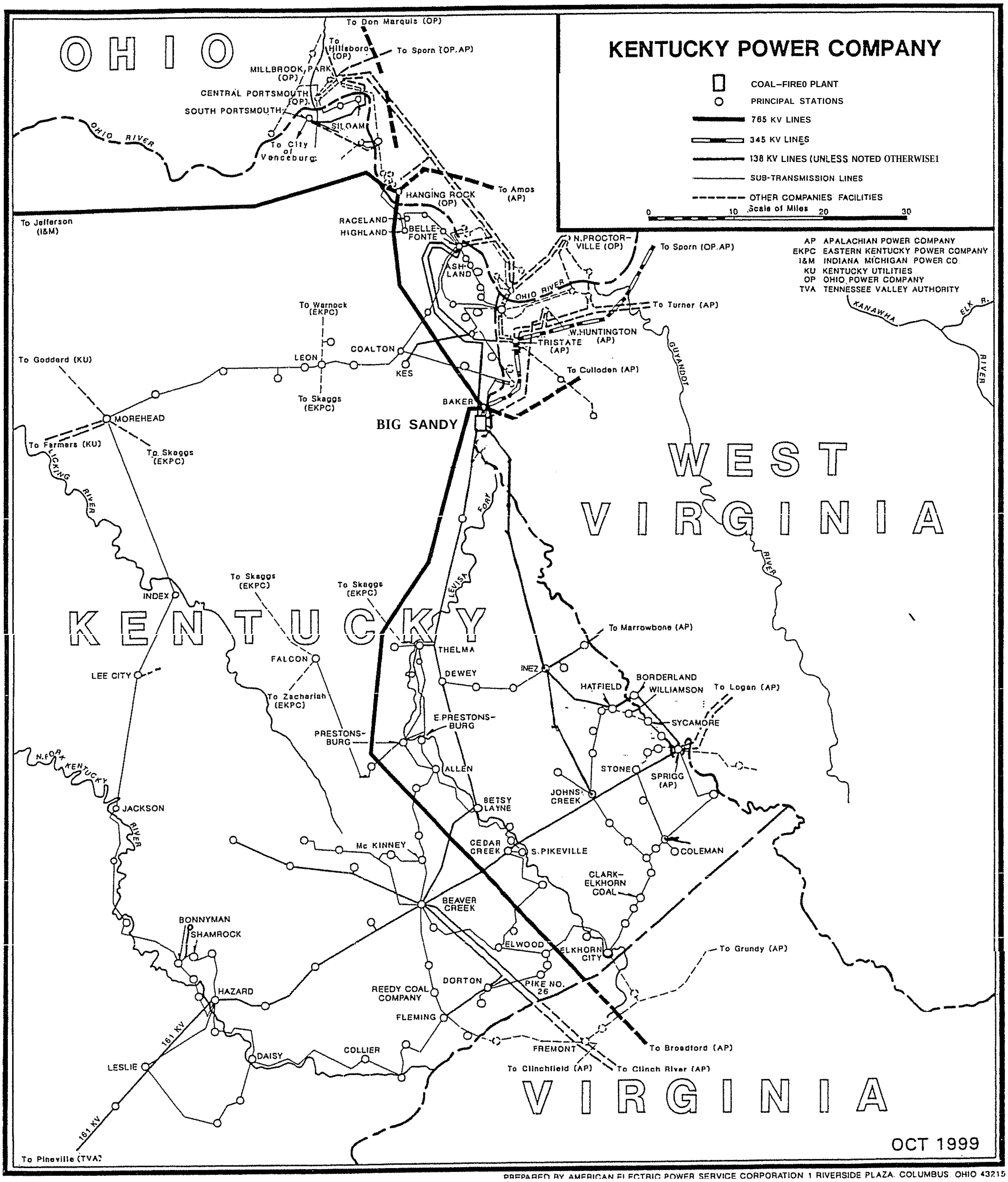
G. KENTUCKY COMMISSION ORDER – ADM CASE NO. 387 ISSUE ADDRESSED

In the Commission's order in **ADM** Case No. **387** page **93** dated December **20,2001** required all utilities to conduct a renewed analysis of appropriate reserve margins to be used for planning purposes and shall include that analysis in their next IRP filed pursuant to KAR 5:058.

Section B.2.e. above discusses AEP's assessment of its current reserve margin requirements. In addition, AEP expects to join the PJM Interconnection and participate in its energy market in the first half of 2003. In this market, PJM will impose either a day-ahead operating margin or a seasonal planning margin requirement for each control area. The level of this requirement is currently being studied by PJM. Looking further ahead, the recent FERC NOPR regarding

Standard Market Design is recommending that utilities maintain a minimum planning reserve margin with a proposed minimum requirement of 12%.

Exhibit 4-1



KENTUCKY POWER COMPANY
COAL-FIRED PLANT
PRINCIPAL STATIONS
765 KV LINES
345 KV LINES
138 KV LINES (UNLESS NOTED OTHERWISE)
SUB-TRANSMISSION LINES
OTHER COMPANIES FACILITIES
Scale of Miles
0 10 20 30
AP APALACHIAN POWER COMPANY
EKPC EASTERN KENTUCKY POWER COMPANY
I&M INDIANA MICHIGAN POWER CO.
KU KENTUCKY UTILITIES
OP OHIO POWER COMPANY
TVA TENNESSEE VALLEY AUTHORITY
OHIO
KENTUCKY
WEST VIRGINIA
VIRGINIA
BIG SANDY
OCT 1999
PREPARED BY AMERICAN ELECTRIC POWER SERVICE CORPORATION 1 RIVERSIDE PLAZA, COLUMBUS, OHIO 43215

KPCO 2002

Exhibit 4-2

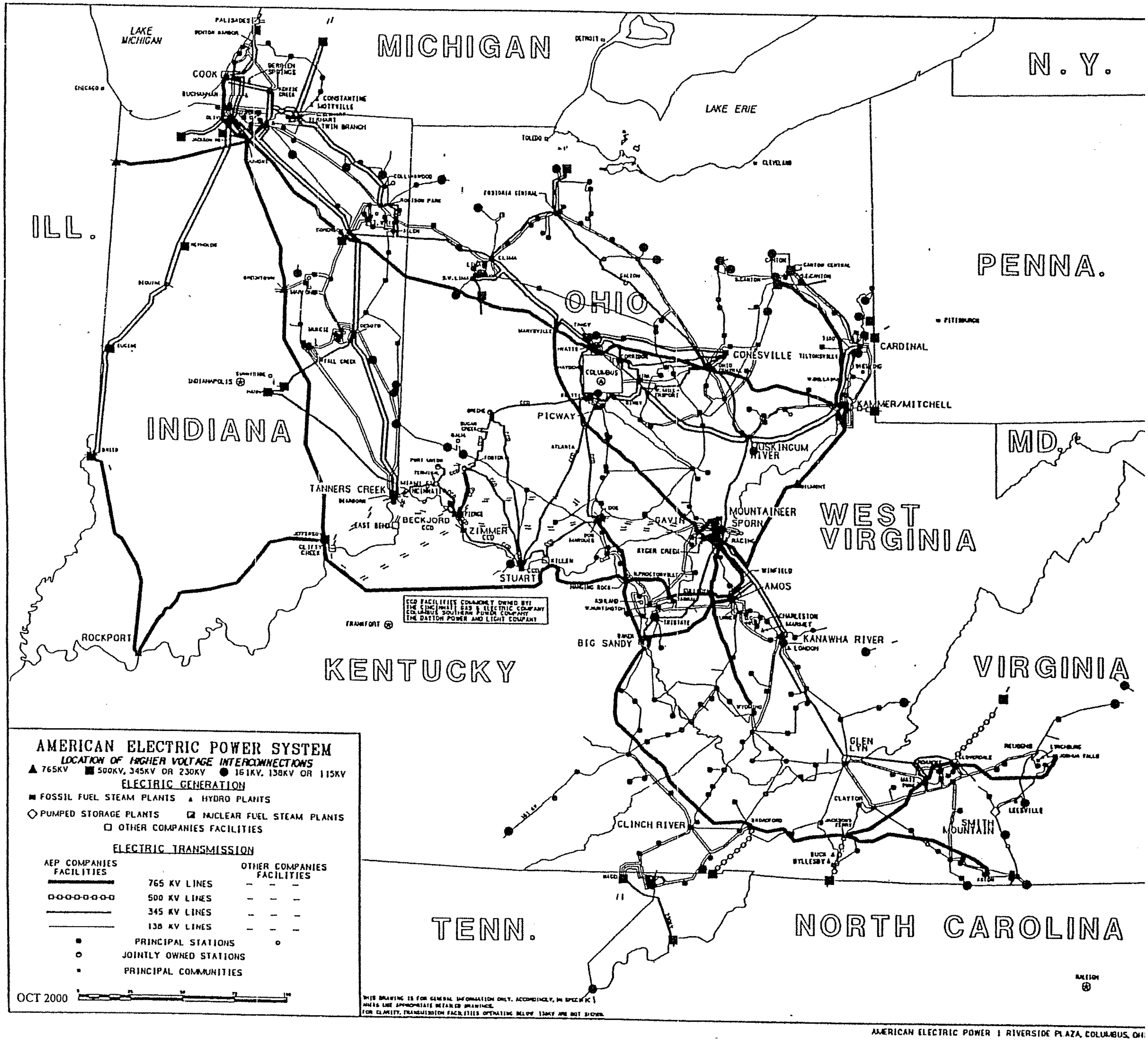


Exhibit **4-3**

KENTUCKY POWER COMPANY

AEP SYSTEM INTERCONNECTIONS IN KENTUCKY AREA

			RATINGS (MVA) NORMAL/EMERGENCY	
FROM	TO	VOLTAGE (KV)	SUMMER	WINTER
AEP-CG&E INTERCONNECTIONS				
Tanners Creek (AEP/I&M)*	– East Bend	345	1195/1315	1195/1315
Tanners Creek (AEP/I&M)*	– Miami Fort**	345-138	400/440	400/440
Collinsville (AEP/OPC)**	– Collinsville(CG&E)**	138-69	80/88	80/88
Trenton (AEP/OPC)**	– Trenton (CG&E)**	138-12	25/25	25/25
Total			1700/1868	1700/1868
AEP-EKPC INTERCONNECTIONS				
Falcon (AEP/KPC)	– Falcon (EKPC)	46-69	22/25	25/27
Leon (AEP/KPC)	– Leon (EKPC)	69	39/46	54/54
Thelma (AEPIKPC)	– Thelma (EKPC)	69	35/35	44/44
Argentum (AEP/KPC)	– Argenturn (EKPC)	69	39/46	54/58
Total			1351152	1771183
AEP-KU INTERCONNECTIONS				
Hillsboro (AEP/OPC)**	– Kenton	138	1641191	1911191
Total			242/292	294/298
AEP-LG&E INTERCONNECTIONS				
Jefferson (AEP/I&M)	– Clifty Creek*	345	1200/1200	1200/1200
AEP-TVA INTERCONNECTIONS				
Hazard (AEP/KPC)	– Pineville	161	172/172	196/196

Notes

* Located in Indiana

** Located in Ohio

Exhibit 4-4

KENTUCKY POWER COMPANY
EXISTING ELECTRIC GENERATING FACILITIES
As of (1/1/02)

Unit	Summer Rating (MW)	Winter Rating (MW)
Big Sandy 1	260	260
Big Sandy 2	800	800
Total Installed Capability	1.060	1,060
Unit Power Purchase	390	390
Total Including Purchase	1,450	1,450

Note: Unit power purchase of 390 MW from Rockport plant. Assumes contract: for 195 MW from Rockport 1 through 2009 and 195 MW from Rockport Unit 2 through December 7, 2022 or end of lease agreement.

REGULATED AMERICAN ELECTRIC POWER EAST SYSTEM
EXISTING ELECTRIC GENERATING FACILITIES
(as of 1/1/02)

Plant Name	Location	Unit No.	Operation Date	Net Capability Winter (MW)	Net Capability Summer (MW)	Fuel Type	Plant Fuel Storage Capacity (Tons000)
Fossil-Steam Units							
John E Amos	St Albans, WV	1	1971	800	800	Coal	1,750
		2	1972	800	800	Coal	--
		3	1973	433	433	Coal	--
Big Sandy	Louisa, KY	1	1963	260	260	Coal	1,750
		2	1969	800	800	Coal	--
Clinch River	Carbo, VA	1	1958	235	230	Coal	500
		2	1958	235	230	Coal	--
		3	1961	235	230	Coal	--
Glen Lyn	Glen Lyn, VA	5	1944	95	90	Coal	160
		6	1957	240	235	Coal	--
Kanawha River	Glasgow, WV	I	1953	200	195	Coal	300
		2	1953	200	195	Coal	--
Mountaineer	New Haven, WV	1	1980	1,300	1,300	Coal	2,100
Philip Sporn	Graham Station, WV	1	1950	150	145	Coal	750
		3	1951	150	145	Coal	--
Rockport	Rockport, IN	1	1984	845 (A)	845 (A)	Coal	2,500
		2	1989	1,300 (A)	1,300 (A)	Coal	--
Tanners Creek	Lawrenceburg, IN	1	1951	145	140	Coal	400
		2	1952	145	140	Coal	--
		3	1954	205	200	Coal	--
		4	1964	500	500	Coal	--
	Total Fossil-Steam			9,273	9,213		
Nuclear-Steam Units							
Cook Nuclear	Bridgman, MI	1	1975	1,020	1,000	Uran	
		2	1978	1,090	1,060	Uran.	--
	Total Nuclear-Steam			2,110	2,060		

REGULATED AMERICAN ELECTRIC POWER EAST SYSTEM
EXISTING ELECTRIC GENERATING FACILITIES
(as of 1/1/02)

Plant Name	Location	Unit No.	Operation Date	Net Capability Winter (MW)	Net Capability Summer (MW)	Fuel Type	Plant Fuel Storage Capacity (Tons000)
Conventional Hvdro Units							
Berrien Springs	Berrien Springs, IN	1,3,4	1908	3 (C)	-- (D)	--	--
		2	1918	--	-- (D)	--	--
Buchanan	Buchanan, MI	1,2	1919	2 (C)	-- (D)	--	--
		3-6	1920	--	-- (D)	--	--
		7-10	1927	--	-- (D)	--	--
Buck	Ivanhoe, VA	1-3	1912	10	-- (D)	--	--
Byllesby	Byllesby, VA	1-4	1912	20	-- (D)	--	--
Claytor	Radford, VA	1-4	1939	76	-- (D)	--	--
Constantine	Constantine, MI	1,4	1923	1 (C)	-- (D)	--	--
		2,3	1921	--	-- (D)	--	--
Elkhart	Elkhart. IN	1	1921	1 (C)	-- (D)	--	--
		2,3	1913	--	-- (D)	--	--
Leesville	Leesville. VA	1	1964	20	-- (D)	--	--
		2	1964	20	-- (D)	--	--
London	Montgomery, WV	1-3	1935	16	-- (D)	--	--
Marmet	Marmet, WV	1-3	1935	16	-- (D)	--	--
Mottville	Mottville, MI	1-4	1923	1	-- (D)	--	--
Niagara	Roanoke, VA	1	1954	3 (C)	-- (D)	--	--
		2	1954	--	-- (D)	--	--
Reusens	Lynchburg, VA	1-5	1903	12	-- (D)	--	--
Twin Branch	Mishawaka, IN	1.6	1989(E)	3 (C)	-- (D)	--	--
		2-5	1992(E)	--	-- (D)	--	--
Winfield	Winfield, WV	1-3	1938	19	-- (D)	--	--
	'Total Conventional Hydro			223	186		
Pumped Storaqe Hydro Units							
Smith Mountain	Penhook, VA	1	1965	70	70	--	
		2	1965	160	160	--	--
		3	1980	105	105	--	--
		4	1966	160	160	--	--
		5	1966	70	70	--	--
	Total Pumped Storage Hydro			565	565		
		Total Before Adjustments		12,171	12,024		
		Unit Power Sale Adjustment (F)		(250)	(250)		
		Total After Adjustments		11,921	11,774		

**REGULATED AMERICAN ELECTRIC POWER SYSTEM
EXISTING ELECTRIC GENERATING FACILITIES
(as of 1/1/02)**

Notes (A) Unit 1 of the Rockport Plant is owned one-half by AEP Generating Company (AEG) and one-half by I&M. Unit 2 is leased one-half by AEG and one-half by I&M The leases commenced in 1989 and terminate in 2022 unless extended. Unit power agreements between AEG and I&M provide for the purchase by I&M of 910 MW from AEG's 1,300-MW share in the Rockport plant Effective January 1, 1990, 250 MW of I&M's leased share of Rockport Unit 2 was allocated to the Unit Power sale to CP&L through December 31, 2009

(B) Additional storage capacity of 150 thousand tons is available at Cook Terminal

(C) Plant total

(D) Summer net capability values are not available on an individual plant basis for this conventional hydro plant

(E) Twin Branch Hydro Plant was originally constructed from 1904 - 1922 New turbine/generators were placed in service in 1989 and 1992.

(F) Reflects the 250-MW unit power sale from Rockport to CP&L through 12/31/09

AMERICAN ELECTRIC POWER SYSTEM
STEAM GENERATING-CAPACITY PRODUCTION COST AND OPERATING INFORMATION
2001

Plant Name	PLANT COST DATA: Average Fuel Cost (¢/MBtu)	Non-Fuel Variable O&M ($000)	Fixed O&M ($000)	Average Variable Production Cost (¢/kWh)	Average Total Production Cost (¢/kWh)	UNIT OPERATING DATA: Unit Number	Capacity Factor (%)	Equivalent Availability Factor (%)	Average Heat Rate (Btu/kWh)
Amos	130.65	10,903	21,438	13.77	15.88	1	56.3	72.8	9,631
						2	68.0	83.2	9,284
						3	37.7	51.9	10,018
Big Sandy	104.97	4,594	11,560	10.67	12.20	1	84.0	95.7	9,617
						2	79.7	91.8	9,447
Clinch	138.05	4,473	10,636	14.21	16.73	1	66.8	86.3	9,589
						2	69.7	91.6	9,459
						3	68.4	91.4	9,396
Cook	47.89	33.491	244,748	1.32	22.79	1	87.4	86.9	0
						2	84.0	84.2	0
Glen Lyn	148.04	4,157	8,530	18.25	24.10	5	41.5	79.3	10,869
						6	52.9	86.7	10,869
Kanawha	115.03	2,524	6,804	12.34	14.98	1	69.3	88.8	9,765
						2	77.7	94.0	9,851
Mountaineer	150.10	8,610	13,174	16.15	18.30	1	53.7	82.9	9,611
Rockport	118.89	9,066	158,769	12.23	21.26	1	75.0	88.8	9,757
						2	79.3	92.7	9,723
Sporn	132.01	1,563	5,755	14.50	17.94	1	60.5	85.2	10,499
Tanners	136.09	8,116	20,465	14.25	18.25	1	61.0	93.9	10,297
						2	59.2	87.9	10.190
						3	62.6	93.8	9,874
	113.28					4	56.3	84.2	9,950

Exhibit D-6

KPCO 2002

Exhibit 4-7
(Page 1 of 2)

REGULATED AEP EAST

Projected Summer Peak Demands, Generating Capabilities and Reserve Margins - MW
2002 - 2016
Without Expanded DSM and Additional Resources

			2002 *	2003	2004	2005	2006	2007	2008	2009
DEMAND										
1	Base Peak Internal Demand		19,577	10,950	11,225	11,455	11,631	11,856	12,031	12,263
2	Expanded DSM Programs									
3	Adjusted Peak Internal Demand		19,577	10,950	11,225	11,455	11,631	11,856	12,031	12,263
4	Committed Capacity Sales		20	270	250	250	250	250	250	250
5	Total Peak Demand		19,597	11,220	11,475	11,705	11,881	12,106	12,281	12,513
6	Interruptible Load		622	306	306	306	306	306	306	306
7	Total Peak Demand Excluding Interruptible Load		18,975	10,914	11,169	11,399	11,575	11,800	11,975	12,207
GENERATING CAPABILITY (Seasonal)										
8	Capacity Before Changes		23,438	11,179	11,179	11,179	11,179	11,179	11,179	11,179
9	Capacity Changes									
	Additions		-	-	-	-	-	-	-	-
	Retirements		-	-	-	-	-	-	-	-
	Total		-	-	-	-	-	-	-	-
10	Capacity After Changes		23,438	11,179	11,179	11,179	11,179	11,179	11,179	11,179
11	Unit Power									
	Purchases		-	845	845	845	845	845	845	845
	Sales		(705)	(250)	(250)	(250)	(250)	(250)	(250)	(250)
12	Net Capacity		22,733	11,774	11,774	11,774	11,774	11,774	11,774	11,774
13	Purchases		16	616	616	616	616	166	166	16
14	Total Capability		22,749	12,390	12,390	12,390	12,390	11,940	11,940	11,790
RESERVE MARGIN										
	Based on Including Interruptible Load									
15	MW	(14)-(5)	3,152	1,170	915	685	509	(166)	(341)	(723)
16	Percent of Demand	[(15)/(5)]x100	161	104	80	59	43	(14)	(28)	(58)
	Based on Excluding Interruptible Load									
17	MW	(14)-(7)	3,774	1,476	1,221	991	815	140	(35)	(417)
18	Percent of Demand	[(17)/(7)]x100	19.9	13.5	109	8.7	70	12	(0.3)	(34)

* Based on AEP East 5 Company.

Exhibit 4-7
(Page 2 of 2)

REGULATED AEP EAST

Projected Summer Peak Demands, Generating Capabilities and Reserve Margins - MW
2002 - 2016

Without Expanded DSM and Additional Resources

		2010	2011	2012	2013	2014	2015	2016
DEMAND								
1 Base Peak Internal Demand		12,450	12,647	12,802	13,049	13,261	13,476	13,651
2 Expanded DSM Programs								
3 Adjusted Peak Internal Demand		12,450	12,647	12,802	13,049	13,261	13,476	13,651
4 Committed Capacity Sales		250	250	250	250	250	250	250
5 Total Peak Demand		12,700	12,897	13,052	13,299	13,511	13,726	13,901
6 Interruptible Load		306	306	306	306	306	306	306
7 Total Peak Demand Excluding Interruptible Load		12,394	12,591	12,746	12,993	13,205	13,420	13,595
GENERATING CAPABILITY (Seasonal)								
8 Capacity Before Changes		11,179	11,179	11,179	11,179	11,179	11,179	11,179
9 Capacity Changes								
Additions		-	-	-	-	-	-	-
Retirements		-	-	-	-	-	-	-
Total		-	-	-	-	-	-	-
10 Capacity After Changes		11,179	11,179	11,179	11,179	11,179	11,179	11,179
11 Unit Power								
Purchases		650	650	650	650	650	650	650
Sales								
12 Net Capacity		11,829	11,829	11,829	11,829	11,829	11,829	11,829
13 Purchases		16	16	16	16	16	16	16
14 Total Capability		11,845	11,845	11,845	11,845	11,845	11,845	11,845
RESERVE MARGIN								
Based on Including Interruptible Load								
15 MW	(14)-(5)	(855)	(1,052)	(1,207)	(1,454)	(1,666)	(1,881)	(2,056)
16 Percent of Demand	[(15)/(5)]x100	(67)	(82)	(92)	(109)	(12.3)	(13.7)	(14.8)
Based on Excluding Interruptible Load								
17 MW	(14)-(7)	(549)	(746)	(901)	(1,148)	(1,360)	(1,575)	(1,750)
18 Percent of Demand	[(17)/(7)]x100	(44)	(59)	(7 1)	(88)	(10.3)	(11 7)	(12.9)

Exhibit **4-8**
(Page 1 of 2)

REGULATED AEP EAST

Projected Winter Peak Demands, Generating Capabilities and Reserve Margins - MW
2002/03 - 2016/17

Without Expanded DSM and Additional Resources

			2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10
	DEMAND									
1	Base Peak Internal Demand		11,438	11,721	11,956	12,133	12,367	12,548	12,788	12,982
2	Expanded DSM Programs									
3	Adjusted Peak Internal Demand		11,438	11,721	11,956	12,133	12,367	12,548	12,788	12,982
4	Committed Capacity Sales		270	250	250	250	250	250	250	250
5	Total Peak Demand		11,708	11,971	12,206	12,383	12,617	12,798	13,038	13,232
6	Interruptible Load		307	307	307	307	307	307	307	307
7	Total Peak Demand Excluding Interruptible Load		11,401	11,664	11,899	12,076	12,310	12,491	12,731	12,925
	GENERATING CAPABILITY (Seasonal)									
8	Capacity Before Changes		11,326	11,326	11,326	11,326	11,326	11,326	11,326	11,326
9	Capacity Changes									
	Additions		-	-	-	-	-	-	-	-
	Retirements		-	-	-	-	-	-	-	-
	Total		-	-	-	-	-	-	-	-
10	Capacity After Changes		11,326	11,326	11,326	11,326	11,326	11,326	11,326	11,326
11	Unit Power									
	Purchases		845	845	845	845	845	845	845	650
	Sales		(250)	(250)	(250)	(250)	(250)	(250)	(250)	-
12	Net Capacity		11,921	11,921	11,921	11,921	11,921	11,921	11,921	11,976
13	Purchases		1,024	1,024	1,024	1,024	1,174	174	24	24
14	Total Capability		12,945	12,945	12,945	12,945	13,095	12,095	11,945	12,000
	RESERVE MARGIN									
	Based on Including Interruptible Load									
15	MW	(14)-(5)	1,237	974	739	562	478	(703)	(1,093)	(1,232)
16	Percent of Demand	[(15)/(5)]x100	10.6	8.1	6.1	4.5	3.8	(5.5)	(8.4)	(9.3)
	Based on Excluding Interruptible Load									
17	MW	(14)-(7)	1,544	1,281	1,046	869	785	(396)	(786)	(925)
18	Percent of Demand	[(17)/(7)]x100	13.5	11.0	8.8	7.2	6.4	(3.2)	(6.2)	(7.2)

Exhibit **4-8**
(Page 2 *of* 2)

REGULATED AEP EAST

Projected Winter Peak Demands, Generating Capabilities and Reserve Margins - MW
2002/03 - 2016/17

Without Expanded DSM and Additional Resources

		2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
DEMAND								
1 Base Peak Internal Demand		13,186	13,345	13,602	13,824	14,047	14,230	14,483
2 Expanded DSM Programs								
3 Adjusted Peak Internal Demand		13,186	13,345	13,602	13,824	14,047	14,230	14,483
4 Committed Capacity Sales		250	250	250	250	250	250	250
5 Total Peak Demand		13,436	13,595	13,852	14,074	14,297	14,480	14,733
6 Interruptible Load		307	307	307	307	307	307	307
7 Total Peak Demand Excluding Interruptible Load		13,129	13,288	13,545	13,767	13,990	14,173	14,426
GENERATING CAPABILITY (Seasonal)								
8 Capacity Before Changes		11,326	11,326	11,326	11,326	11,326	11,326	11,326
9 Capacity Changes								
Additions		-	-	-	-	-	-	-
Retirements		-	-	-	-	-	-	-
Total		-	-	-	-	-	-	-
10 Capacity After Changes		11,326	11,326	11,326	11,326	11,326	11,326	11,326
11 Unit Power								
Purchases		650	650	650	650	650	650	650
Sales								
12 Net Capacity		11,976	11,976	11,976	11,976	11,976	11,976	11,976
13 Purchases		24	24	24	24	24	24	24
14 Total Capability		12,000	12,000	12,000	12,000	12,000	12,000	12,000
RESERVE MARGIN								
Based on Including Interruptible Load								
15 MW	(14)-(5)	(1,436)	(1,595)	(1,852)	(2,074)	(2,297)	(2,480)	(2,733)
16 Percent of Demand	[(15)/(5)]x100	(10.7)	(11.7)	(134)	(147)	(16.1)	(17.1)	(186)
Based on Excluding Interruptible Load								
17 MW	(14)-(7)	(1,129)	(1,288)	(1,545)	(1,767)	(1,990)	(2,173)	(2,426)
18 Percent of Demand	[(17)/(7)]x100	(86)	(9.7)	(11 4)	(12.8)	(142)	(15.3)	(16 8)

Exhibit 4-9

KENTUCKY POWER COMPANY

Projected Summer Peak Demands, Generating Capabilities and Reserve Margins - MW
2002 - 2016

Without Expanded DSM and Additional Resources

		2002	2003	2004	2005	2006	2007	2008	2009
DEMAND									
1 Base Peak Internal Demand		1,271	1,286	1,331	1,363	1,357	1,389	1,412	1,440
2 Expanded DSM Programs									
3 Adjusted Peak Internal Demand		1,271	1,286	1,331	1,363	1,357	1,389	1,412	1,440
4 Committed Capacity Sales		0	30	15	10	39	44	44	45
5 Total Peak Demand		1,271	1,316	1,346	1,373	1,396	1,433	1,456	1,485
6 Interruptible Load		0	0	0	0	0	0	0	0
7 Total Peak Demand Excluding Interruptible Load		1,271	1,316	1,346	1,373	1,396	1,433	1,456	1,485
GENERATING CAPABILITY (Seasonal]									
8 Capacity Before Changes		1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060
9 Capacity Changes									
Additions									
Retirements									
Total									
10 Capacity After Changes		1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060
11 Unit Power Purchase		390	390	390	390	390	390	390	390
12 Net Capacity		1,450	1,450	1,450	1,450	1,450	1,450	1,450	1,450
13 Purchases									
14 Total Capability		1,450	1,450	1,450	1,450	1,450	1,450	1,450	1,450
RESERVE MARGIN									
Based on Including Interruptible Load									
15 MW	(14)-(5)	179	134	104	77	54	17	(6)	(35)
16 Percent of Demand	[(15)/(5)]x100	141	102	77	56	39	12	(04)	(24)
Based on Excluding Interruptible Load									
17 MW	(14)-(7)	179	134	104	77	54	17	(6)	(35)
18 Percent of Demand	[(17)/(7)]x100	141	102	77	5.6	3.9	1.2	(04)	(2.4)

KENTUCKY POWER COMPANY

Projected Summer Peak Demands, Generating Capabilities and Reserve Margins - MW
2002 - 2016

Without Expanded DSM and Additional Resources

			2010	2011	2012	2013	2014	2015	2016
	DEMAND								
1	Base Peak Internal Demand		1,462	1,486	1,504	1,535	1,560	1,585	1,606
2	Expanded DSM Programs								
3	Adjusted Peak Internal Demand		1,462	1,486	1,504	1,535	1,560	1,585	1,606
4	Committed Capacity Sales		0	0	0	0	0	0	0
5	Total Peak Demand		1,462	1,486	1,504	1,535	1,560	1,585	1,606
6	Interruptible Load		0	0	0	0	0	0	0
7	Total Peak Demand Excluding Interruptible Load		1,462	1,486	1,504	1,535	1,560	1,585	1,606
	GENERATING CAPABILITY (Seasonal)								
8	Capacity Before Changes		1,060	1,060	1,060	1,060	1,060	1,060	1,060
9	Capacity Changes								
	Additions		-	-	-	-	-	-	-
	Retirements		-	-	-	-	-	-	-
	Total		-	-	-	-	-	-	-
10	Capacity After Changes		1,060	1,060	1,060	1,060	1,060	1,060	1,060
11	Unit Power Purchase		195	195	195	195	195	195	195
12	Net Capacity		1,255	1,255	1,255	1,255	1,255	1,255	1,255
13	Purchases		-	-	-	-	-	-	-
14	Total Capability		1,255	1,255	1,255	1,255	1,255	1,255	1,255
	RESERVE MARGIN								
	Based on Including Interruptible Load								
15	MW	(14)-(5)	(207)	(231)	(249)	(280)	(305)	(330)	(351)
16	Percent of Demand	[(15)/(5)]x100	(142)	(155)	(166)	(182)	(19.6)	(208)	(219)
	Based on Excluding Interruptible Load								
17	MW	(14)-(7)	(207)	(231)	(249)	(280)	(305)	(330)	(351)
18	Percent of Demand	[(17)/(7)]x100	(14.2)	(155)	(16.6)	(18.2)	(196)	(208)	(21.9)

Exhibit 4-10
(Page 1 of 2)

KENTUCKY POWER COMPANY

Projected Winter Peak Demands, Generating Capabilities and Reserve Margins - MW
2002103 - 2016/17

Without Expanded DSM and Additional Resources

		2002103	2003104	2004105	2005106	2006107	2007108	2008109	2009110
DEMAND									
1 Base Peak Internal Demand		1,503	1,554	1,592	1,586	1,624	1,651	1,684	1,709
2 Expanded DSM Programs									
3 Adjusted Peak Internal Demand		1,503	1,554	1,592	1,586	1,624	1,651	1,684	1,709
4 Committed Capacity Sales		0	0	0	0	0	0	0	0
5 Total Peak Demand		1,503	1,554	1,592	1,586	1,624	1,651	1,684	1,709
6 Interruptible Load		0	0	0	0	0	0	0	0
7 Total Peak Demand Excluding Interruptible Load		1,503	1,554	1,592	1,586	1,624	1,651	1,684	1,709
GENERATING CAPABILITY (Seasonal)									
8 Capacity Before Changes		1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060
9 Capacity Changes									
Additions		-	-	-	-	-	-	-	-
Retirements		-	-	-	-	-	-	-	-
Total		-	-	-	-	-	-	-	-
10 Capacity After Changes		1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060
11 Unit Power Purchase		390	390	390	390	390	390	390	195
12 Net Capacity		1,450	1,450	1,450	1,450	1,450	1,450	1,450	1,255
13 Purchases									
14 Total Capability		1,450	1,450	1,450	1,450	1,450	1,450	1,450	1,255
RESERVE MARGIN									
Based on Including Interruptible Load									
15 MW	(14)-(5)	(53)	(104)	(142)	(136)	(174)	(201)	(234)	(454)
16 Percent of Demand	[(15)/(5)]x100	(35)	(6.7)	(8.9)	(8.6)	(107)	(12.2)	(139)	(266)
Based on Excluding Interruptible Load									
17 MW	(14)-(7)	(53)	(104)	(142)	(136)	(174)	(201)	(234)	(454)
18 Percent of Demand	[(17)/(7)]x100	(35)	(67)	(89)	(8.6)	(107)	(12.2)	(139)	(266)

KENTUCKY POWER COMPANY

Projected Winter Peak Demands, Generating Capabilities and Reserve Margins - MW
2002103 - 2016/17

Without Expanded DSM and Additional Resources

		2010/11	201 1/12	2012/13	2013/14	2014115	2015/16	2016/17
DEMAND								
1 Base Peak Internal Demand		1,737	1,758	1,794	1,823	1,853	1,878	1,911
2 Expanded DSM Programs								
3 Adjusted Peak Internal Demand		1,737	1,758	1,794	1,823	1,853	1,878	1,911
4 Committed Capacity Sales		0	0	0	0	0	0	0
5 Total Peak Demand		1,737	1,758	1,794	1,823	1,853	1,878	1,911
6 Interruptible Load		0	0	0	0	0	0	0
7 Total Peak Demand Excluding Interruptible Load		1,737	1,758	1,794	1,823	1,853	1,878	1,911
GENERATING CAPABILITY (Seasonal)								
8 Capacity Before Changes		1,060	1,060	1,060	1,060	1,060	1,060	1,060
9 Capacity Changes								
Additions		-	-	-	-	-	-	-
Retirements		-	-	-	-	-	-	-
Total		-	-	-	-	-	-	-
10 Capacity After Changes		1,060	1,060	1,060	1,060	1,060	1,060	1,060
11 Unit Power Purchase		195	195	195	195	195	195	195
12 Net Capacity		1,255	1,255	1,255	1,255	1,255	1,255	1,255
13 Purchases		-	-	-	-	-	-	-
14 Total Capability		1,255	1,255	1,255	1,255	1,255	1,255	1,255
RESERVE MARGIN								
Based on Including Interruptible Load								
15 MW	(14)-(5)	(482)	(503)	(539)	(568)	(598)	(623)	(656)
16 Percent of Demand	[(15)/(5)]x100	(277)	(286)	(30.0)	(31.2)	(323)	(332)	(343)
Based on Excluding Interruptible Load								
17 MW	(14)-(7)	(482)	(503)	(539)	(568)	(598)	(623)	(656)
18 Percent of Demand	[(17)/(7)]x100	(277)	(28.6)	(30.0)	(31.2)	(32.3)	(33.2)	(34.3)

REGULATED AEP EAST

Projected Summer Peak Demands, Generating Capabilities and Reserve Margins - MW
2002 - 2016

With Expanded DSM and Additional Resources

		2002 *	2003	2004	2005	2006	2007	2008	2009
DEMAND									
1 Base Peak Internal Demand		19,577	10,950	11,225	11,455	11,631	11,856	12,031	12,263
2 Expanded DSM Programs		-	(1)	(1)	(1)	(2)	(2)	(2)	(2)
3 Adjusted Peak Internal Demand		19,577	10,949	11,224	11,454	11,629	11,854	12,029	12,261
4 Committed Capacity Sales		20	270	250	250	250	250	250	250
5 Total Peak Demand		19,597	11,219	11,474	11,704	11,879	12,104	12,279	12,511
6 Interruptible Load		622	306	306	306	306	306	306	306
7 Total Peak Demand Excluding Interruptible Load		18,975	10,913	11,168	11,398	11,573	11,798	11,973	12,205
GENERATING CAPABILITY (Seasonal)									
8 Capacity Before Changes		23,438	11,179	11,179	11,179	11,179	11,179	11,179	11,179
9 Capacity Changes									
Additions		-	-	-	-	-	-	-	-
Retirements		-	-	-	-	-	-	-	-
Total		-	-	-	-	-	-	-	-
10 Capacity After Changes		23,438	11,179	11,179	11,179	11,179	11,179	11,179	11,179
11 Unit Power									
Purchases		-	845	845	845	845	845	845	845
Sales		(705)	(250)	(250)	(250)	(250)	(250)	(250)	(250)
12 Net Capacity		22,733	11,774	11,774	11,774	11,774	11,774	11,774	11,774
13 Purchases									
Committed		16	616	616	616	616	166	166	16
Uncammitted			-	150	400	600	1,300	1,500	1,900
14 Total Capability		22,749	12,390	12,540	12,790	12,990	13,240	13,440	13,690
RESERVE MARGIN									
Based on Includinq Interruptible Load									
15 MW	(14)-(5)	3,152	1,171	1,066	1,086	1,111	1,136	1,161	1,179
16 Percent of Demand	[(15)/(5)]x100	161	104	93	93	94	94	95	94
Based on Excludinq Interruptible Load									
17 MW	(14)-(7)	3,774	1,477	1,372	1,392	1,417	1,442	1,467	1,485
18 Percent of Demand	[(17)/(7)]x100	199	135	123	122	122	122	123	122

* Based on AEP East 5 Company.

REGULATED AEP EAST

Projected Summer Peak Demands, Generating Capabilities and Reserve Margins - MW
2002 - 2016

With Expanded DSM and Additional Resources

			2010	2011	2012	2013	2014	2015	2016
	DEMAND								
1	Base Peak Internal Demand		12,450	12,647	12,802	13,049	13,261	13,476	13,651
2	Expanded DSM Programs		(2)	(2)	(2)	(2)	(2)	(2)	(2)
3	Adjusted Peak Internal Demand		12,448	12,645	12,800	13,047	13,259	13,474	13,649
4	Committed Capacity Sales		250	250	250	250	250	250	250
5	Total Peak Demand		12,698	12,895	13,050	13,297	13,509	13,724	13,899
6	Interruptible Load		306	306	306	306	306	306	306
7	Total Peak Demand Excluding Interruptible Load		12,392	12,589	12,744	12,991	13,203	13,418	13,593
	GENERATING CAPABILITY (Seasonal)								
8	Capacity Before Changes		11,179	11,179	11,179	11,179	11,179	11,179	11,179
9	Capacity Changes								
	Additions		-	-	-	-	-	-	-
	Retirements		-	-	-	-	-	-	-
	Total		-	-	-	-	-	-	-
10	Capacity After Changes		11,179	11,179	11,179	11,179	11,179	11,179	11,179
11	Unit Power								
	Purchases		650	650	650	650	650	650	650
	Sales								
12	Net Capacity		11,829	11,829	11,829	11,829	11,829	11,829	11,829
13	Purchases								
	Committed		16	16	16	16	16	16	16
	Uncommitted		2,050	2,250	2,450	2,700	2,950	3,200	3,400
14	Total Capability		13,895	14,095	14,295	14,545	14,795	15,045	15,245
	RESERVE MARGIN								
	Based on Including Interruptible Load								
15	MW	(14)-(5)	1,197	1,200	1,245	1,248	1,286	1,321	1,346
16	Percent of Demand	[(15)/(5)]x100	9.4	9.3	95	94	95	9.6	9.7
	Based on Excluding Interruptible Load								
17	MW	(14)-(7)	1,503	1,506	1,551	1,554	1,592	1,627	1,652
18	Percent of Demand	[(17)/(7)]x100	12.1	12.0	122	12.0	121	121	122

Exhibit 4-12
(Page 1 of 2)

REGULATED AEP EAST

Projected Winter Peak Demands, Generating Capabilities and Reserve Margins - MW
2002/03 - 2016/17
With Expanded DSM and Additional Resources

			2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10
	DEMAND									
1	Base Peak Internal Demand		11,438	11,721	11,956	12,133	12,367	12,548	12,788	12,982
2	Expanded DSM Programs		(1)	(2)	(3)	(4)	(4)	(4)	(4)	(4)
3	Adjusted Peak Internal Demand		11,437	11,719	11,953	12,129	12,363	12,544	12,784	12,978
4	Committed Capacity Sales		270	250	250	250	250	250	250	250
5	Total Peak Demand		11,707	11,969	12,203	12,379	12,613	12,794	13,034	13,228
6	Interruptible Load		307	307	307	307	307	307	307	307
7	Total Peak Demand Excluding Interruptible Load		11,400	11,662	11,896	12,072	12,306	12,487	12,727	12,921
	GENERATING CAPABILITY (Seasonal)									
8	Capacity Before Changes		11,326	11,326	11,326	11,326	11,326	11,326	11,326	11,326
9	Capacity Changes									
	Additions		-	-	-	-	-	-	-	-
	Retirements		-	-	-	-	-	-	-	-
	Total		-	-	-	-	-	-	-	-
10	Capacity After Changes		11,326	11,326	11,326	11,326	11,326	11,326	11,326	11,326
11	Unit Power									
	Purchases		845	845	845	845	845	845	845	650
	Sales		(250)	(250)	(250)	(250)	(250)	(250)	(250)	-
12	Net Capacity		11,921	11,921	11,921	11,921	11,921	11,921	11,921	11,976
13	Purchases									
	Committed		1,024	1,024	1,024	1,024	1,174	174	24	24
	Uncommitted		-	150	400	600	700	1,900	2,350	2,500
14	Total Capability		12,945	13,095	13,345	13,545	13,795	13,995	14,295	14,500
	RESERVE MARGIN									
	Based on Including Interruptible Load									
15	MW	(14)-(5)	1,238	1,126	1,142	1,166	1,182	1,201	1,261	1,272
16	Percent of Demand	[(15)/(5)]x100	10.6	9.4	9 4	9.4	9.4	9.4	9 7	9.6
	Based on Excluding Interruptible Load									
17	MW	(14)-(7)	1.545	1.433	1,449	1.473	1.489	1,508	1,568	1,579
18	Percent of Demand	[(17)/(7)]x100	136	123	122	122	12 1	12.1	123	122

Exhibit 4-12
(Page 2 of 2)

REGULATED AEP EAST

Projected Winter Peak Demands, Generating Capabilities and Reserve Margins - MW
2002/03 - 2016/17

With Expanded DSM and Additional Resources

		2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
DEMAND								
1	Base Peak Internal Demand	13,186	13,345	13,602	13,824	14,047	14,230	14,483
2	Expanded DSM Programs	(4)	(4)	(4)	(4)	(4)	(4)	(4)
3	Adjusted Peak Internal Demand	13,182	13,341	13,598	13,820	14,043	14,226	14,479
4	Committed Capacity Sales	250	250	250	250	250	250	250
5	Total Peak Demand	13,432	13,591	13,848	14,070	14,293	14,476	14,729
6	Interruptible Load	307	307	307	307	307	307	307
7	Total Peak Demand Excluding Interruptible Load	13,125	13,284	13,541	13,763	13,986	14,169	14,422
GENERATING CAPABILITY (Seasonal)								
8	Capacity Before Changes	11,326	11,326	11,326	11,326	11,326	11,326	11,326
9	Capacity Changes							
	Additions	-	-	-	-	-	-	-
	Retirements	-	-	-	-	-	-	-
	Total	-	-	-	-	-	-	-
10	Capacity After Changes	11,326	11,326	11,326	11,326	11,326	11,326	11,326
11	Unit Power							
	Purchases	650	650	650	650	650	650	650
	Sales							
12	Net Capacity	11,976	11,976	11,976	11,976	11,976	11,976	11,976
13	Purchases							
	Committed	24	24	24	24	24	24	24
	Uncommitted	2,700	2,900	3,200	3,450	3,700	3,900	4,150
14	Total Capability	14,700	14,900	15,200	15,450	15,700	15,900	16,150
RESERVE MARGIN								
	Based on Including Interruptible Load							
15	MW (14)-(5)	1,268	1,309	1,352	1,380	1,407	1,424	1,421
16	Percent of Demand [(15)/(5)]x100	9.4	9.6	9.8	9.8	9.8	9 8	9 6
	Based on Excluding Interruptible Load							
17	MW (14)-(7)	1,575	1,616	1,659	1,687	1,714	1,731	1,728
18	Percent of Demand [(17)/(7)]x100	12.0	122	123	123	123	122	120

KENTUCKY POWER COMPANY

Projected Summer Peak Demands, Generating Capabilities and Reserve Margins - MW
2002 - 2016
With Expanded DSM and Additional Resources

		2002	2003	2004	2005	2006	2007	2008	2009
DEMAND									
1 Base Peak Internal Demand		1,271	1,286	1,331	1,363	1,357	1,389	1,412	1,440
2 Expanded DSM Programs			(1)	(1)	(1)	(2)	(2)	(2)	(2)
3 Adjusted Peak Internal Demand		1,271	1,285	1,330	1,362	1,355	1,387	1,410	1,438
4 Committed Capacity Sales		0	30	15	10	39	44	44	45
5 Total Peak Demand		1,271	1,315	1,345	1,372	1,394	1,431	1,454	1,483
6 Interruptible Load		0	0	0	0	0	0	0	0
7 Total Peak Demand Excluding Interruptible Load		1,271	1,315	1,345	1,372	1,394	1,431	1,454	1,483
GENERATING CAPABILITY (Seasonal)									
8 Capacity Before Changes		1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060
9 Capacity Changes									
Additions		-	-	-	-	-	-	-	-
Retirements		-	-	-	-	-	-	-	-
Total		-	-	-	-	-	-	-	-
10 Capacity After Changes		1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060
11 Unit Power Purchase		390	390	390	390	390	390	390	390
12 Net Capacity		1,450	1,450	1,450	1,450	1,450	1,450	1,450	1,450
13 Purchases				20	50	70	110	140	170
14 Total Capability		1,450	1,450	1,470	1,500	1,520	1,560	1,590	1,620
RESERVE MARGIN									
Based on Including Interruptible Load									
15 MW	(14)-(5)	179	135	125	128	126	129	136	137
16 Percent of Demand	[(15)/(5)]x100	141	103	9.3	9 3	9 0	9 0	9.4	9 2
Based on Excluding Interruptible Load									
17 MW	(14)-(7)	179	135	125	128	126	129	136	137
18 Percent of Demand	[(17)/(7)]x100	141	10.3	9 3	9.3	9 0	9 0	9 4	9.2

Exhibit 4-13
(Page 2 of 2)

KENTUCKY POWER COMPANY

Projected Summer Peak Demands, Generating Capabilities and Reserve Margins - MW
2002 - 2016

With Expanded DSM and Additional Resources

		2010	2011	2012	2013	2014	2015	2016
DEMAND								
1 Base Peak Internal Demand		1,462	1,486	1,504	1,535	1,560	1,585	1,606
2 Expanded DSM Programs		(2)	(2)	(2)	(2)	(2)	(2)	(2)
3 Adjusted Peak Internal Demand		1,460	1,484	1,502	1,533	1,558	1,583	1,604
4 Committed Capacity Sales		0	0	0	0	0	0	0
5 Total Peak Demand		1,460	1,484	1,502	1,533	1,558	1,583	1,604
6 Interruptible Load		0	0	0	0	0	0	0
7 Total Peak Demand Excluding Interruptible Load		1,460	1,484	1,502	1,533	1,558	1,583	1,604
GENERATING CAPABILITY (Seasonal)								
8 Capacity Before Changes		1,060	1,060	1,060	1,060	1,060	1,060	1,060
9 Capacity Changes								
Additions								
Retirements								
Total								
10 Capacity After Changes		1,060	1,060	1,060	1,060	1,060	1,060	1,060
11 Unit Power Purchase		195	195	195	195	195	195	195
12 Net Capacity		1,255	1,255	1,255	1,255	1,255	1,255	1,255
13 Purchases		340	360	380	410	440	470	490
14 Total Capability		1,595	1,615	1,635	1,665	1,695	1,725	1,745
RESERVE MARGIN								
Based on Including Interruptible Load								
15 MW	(14)-(5)	135	131	133	132	137	142	141
16 Percent of Demand	[(15)/(5)]x100	9.2	8.8	8.9	8.6	8.8	9.0	8.8
Based on Excluding Interruptible Load								
17 MW	(14)-(7)	135	131	133	132	137	142	141
18 Percent of Demand	[(17)/(7)]x100	9.2	8.8	8.9	8.6	8.8	9.0	8.8

Exhibit **4-14**

(Page 1 of *2)*

KENTUCKY POWER COMPANY

Projected Winter Peak Demands, Generating Capabilities and Reserve Margins - MW

2002103 - 2016117

With Expanded DSM and Additional Resources

			2002103	2003104	2004105	2005106	2006107	2007108	2008109	2009110
DEMAND										
1	Base Peak Internal Demand		1,503	1,554	1,592	1,586	1,624	1,651	1,684	1,709
2	Expanded DSM Programs		(1)	(2)	(3)	(4)	(4)	(4)	(4)	(4)
3	Adjusted Peak Internal Demand		1,502	1,552	1,589	1,582	1,620	1,647	1,680	1,705
4	Committed Capacity Sales		0	0	0	0	0	0	0	0
5	Total Peak Demand		1,502	1,552	1,589	1,582	1,620	1,647	1,680	1,705
6	Interruptible Load		0	0	0	0	0	0	0	0
7	Total Peak Demand Excluding Interruptible Load		1,502	1,552	1,589	1,582	1,620	1,647	1,680	1,705
GENERATING CAPABILITY (Seasonal)										
8	Capacity Before Changes		1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060
9	Capacity Changes									
	Additions									
	Retirements									
	Total									
10	Capacity After Changes		1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060
11	Unit Power Purchase		390	390	390	390	390	390	390	195
12	Net Capacity		1,450	1,450	1,450	1,450	1,450	1,450	1,450	1,255
13	Purchases		-	150	240	240	300	350	400	590
14	Total Capability		1,450	1,600	1,690	1,690	1,750	1,800	1,850	1,845
RESERVE MARGIN										
	Based on Including Interruptible Load									
15	MW	(14)-(5)	(52)	48	101	108	130	153	170	140
16	Percent of Demand	[(15)/(5)]x100	(35)	3 1	6 4	6 8	8.0	9 3	101	8 2
	Based on Excluding Interruptible Load									
17	MW	(14)-(7)	(52)	48	101	108	130	153	170	140
18	Percent of Demand	[(17)/(7)]x100	(3.5)	3.1	6.4	6.8	8.0	9.3	10.1	8.2

Exhibit 4-14
(Page 2 of 2)

KENTUCKY POWER COMPANY

Projected Winter Peak Demands, Generating Capabilities and Reserve Margins - MW
2002103 - 2016/17

With Expanded DSM and Additional Resources

			2010/11	2011/12	2012113	2013114	2014115	2015116	2016117
DEMAND									
1	Base Peak Internal Demand		1,737	1,758	1,794	1,823	1,853	1,878	1,911
2	Expanded DSM Programs		(4)	(4)	(4)	(4)	(4)	(4)	(4)
3	Adjusted Peak Internal Demand		1,733	1,754	1,790	1,819	1,849	1,874	1,907
4	Committed Capacity Sales		0	0	0	0	0	0	0
5	Total Peak Demand		1,733	1,754	1,790	1,819	1,849	1,874	1,907
6	Interruptible Load		0	0	0	0	0	0	0
7	Total Peak Demand Excluding Interruptible Load		1,733	1,754	1,790	1,819	1,849	1,874	1,907
GENERATING CAPABILITY (Seasonal)									
8	Capacity Before Changes		1,060	1,060	1,060	1,060	1,060	1,060	1,060
9	Capacity Changes								
	Additions		-	-	-	-	-	-	-
	Retirements		-	-	-	-	-	-	-
	Total		-	-	-	-	-	-	-
10	Capacity After Changes		1,060	1,060	1,060	1,060	1,060	1,060	1,060
11	Unit Power Purchase		195	195	195	195	195	195	195
12	Net Capacity		1,255	1,255	1,255	1,255	1,255	1,255	1,255
13	Purchases		640	670	730	770	810	830	870
14	Total Capability		1,895	1,925	1,985	2,025	2,065	2,085	2,125
RESERVE MARGIN									
	Based on Including Interruptible Load								
15	MW	(14)-(5)	162	171	195	206	216	211	218
16	Percent of Demand	[(15)/(5)]x100	9 3	9 7	10.9	11 3	11 7	11 3	11 4
	Based on Excluding Interruptible Load								
17	MW	(14)-(7)	162	171	195	206	216	211	218
18	Percent of Demand	[(17)/(7)]x100	9 3	9 7	10.9	11 3	11 7	11 3	11.4

Exhibit 4-15

KENTUCKY POWER COMPANY
Annual Internal Energy Requirements, Energy Resources and Energy Inputs
2003 - 2012
(GWh)

	Energy Requirements			Energy Resources								Energy Inputs (By Primary Fuel Type)			
	Base Forecast			Generation (By Primary Fuel Type)					Firm Purchases			Coal-fired Generation		Gas-fired Generation	
Year	Internal Energy Requirements	Conservation & Load Management	Adjusted Energy	Coal	Oil	Gas	Hydro	Total	Other Utilities (A)	NUG	Total (B)	Tons (000)	MBtu (000)	MCF (000)	MBtu (000)
2003	7,702	(5)	7,697	7,779	--	--	--	7.779	2,678	--	10,457	3,086	74,150	--	--
2004	7,993	(7)	7,986	7,711	--	--	--	7,711	2,607	--	10,318	3,067	73,720	--	--
2005	8,150	(10)	8,140	7,695	--	--	--	7,695	2,859	--	10,554	3,055	73,470	--	--
2006	8,125	(11)	8,114	6,914	--	--	--	6,914	2,696	--	9,610	2,744	66,020	--	--
2007	8,322	(11)	8,311	7,739	--	--	--	7,739	2,769	--	10,508	3,074	73,940	--	--
2008	8,480	(11)	8,469	7,719	--	--	--	7,719	2,982	--	10,701	3,062	73,650	--	--
2009	8,620	(11)	8.609	7,963	--	--	--	7,963	2,830	--	10,793	3,164	76,020	--	--
2010	8.750	(11)	8,739	6,795	--	--	--	6,795	1,360	--	8,155	2,703	64,950	--	--
2011	8,884	(11)	8,873	8,011	--	--	--	8,011	1,515	--	9,526	3,181	76,430	--	--
2012	9,037	(11)	9,026	7,661	--	--	--	7,661	1,454	--	9,115	3,044	73,150	--	--

Notes: (A) Rockport Unit Power purchase from AEG (an affiliated company).
(B) The difference between Energy Requirements and Energy Resources represents net energy received from or delivered to the AEP Pool.

Exhibit 4-16

AEP SYSTEM Comparison of 1999 and 2002 Capacity Expansion Plans						
	1999 Plan for 5-Company System (1999-2019)			2002 Plan for 3-Company System (2002-2016)		
	100-MW Block Additions	Allocated MW*		Total Annual Purchases - MW*	Incremental Allocated MW*	
Year	(Undesignated)	AEP	KPCo	(Uncommitted)	AEP	KPCo
2001	-		-	-	-	-
2002	-	-	-	-	-	-
2003	-	-	-	-	-	-
2004	-	-	-	150	150	150
2005	5	500	300	400	250	90
2006	4	400	100	600	200	0
2007	4	400	100	700	100	60
2008	-	-	-	1,900	1,200	50
2009	18	1,800	200	2,350	450	50
2010	1	100	-	2,500	150	190
2011	7	700	100	2,700	200	50
2012	4	400	-	2,900	200	30
2013	8	800	-	3,200	300	60
2014	7	700	100	3,450	250	40
2015	15	1,500	100	3,700	250	40
2016	4	400	-	3,900	200	20
2017	4	400	-	4,150	250	40
2018	6	600	100	-	-	-
2019	4	400	-	-	-	-
Through 2017		8,100	1,000	4,150	4,150	870
Through 2019		9,100	1,100	4,150	4,150	870

* Winter capacity of the indicated year.

Kentucky Power Company

Model Equations

Results of Statistical Tests and Input Data Sets

Pertaining to the 2002 Load Forecast

Contents

Included herein are input data, model equations, and statistical results for the numerous forecasting models employed in developing the 2002 Load Forecast for Kentucky Power Company. Those forecasted concepts that are produced judgmentally, without the use of econometric models, are not shown. The pages included are as output from the computer model. In most cases, that output contains a data glossary, identifying the names of variables appearing in the models (or the variables labeled in the equations). The one exception is the output for the short-term energy models, to which a data glossary has been added. The models are shown in the following order:

Short-term Energy Models
(for Data Glossary see pages 105-128)

The ARIMA Procedure

Maximum Likelihood Estimation

Parameter	Estimate	Standard Error	t Value	Approx Pr > |t|	Lag	Variable	Shift
MU	88.94732	20.33243	4.37	<.0001	0	CUST	0
MA1,1	-0.30349	0.09079	-3.34	0.0008	11	CUST	0
MA2,1	0.24465	0.08304	2.95	0.0032	1	CUST	0
MA2,2	-0.29478	0.08464	-3.48	0.0005	13	CUST	0
AR1,1	-0.16889	0.07931	-2.13	0.0332	5	CUST	0
AR1,2	0.40306	0.08052	5.01	<.0001	12	CUST	0
NUM1	-3942.4	111.80863	-35.26	<.0001	0	res1	0
NUM2	8977.9	108.76098	82.55	<.0001	0	res2	0

Constant Estimate	68.11886
Variance Estimate	20905.34
Std Error Estimate	144.5868
AIC	1725.789
SBC	1748.972
Number of Residuals	134

The ARIMA Procedure

Correlations of Parameter Estimates

Variable		CUST	CUST	CUST	CUST	CUST	CUST	res1	res2
Parameter		MU	MA1,1	MA2,1	MA2,2	AR1,1	AR1,2	NUM1	NUM2
CUST	MU	1.000	0.005	-0.015	0.013	0.018	-0.048	-0.003	-0.007
CUST	MA1,1	0.005	1.000	-0.129	-0.030	-0.107	0.014	0.237	-0.026

CUST	MA2,1	-0.015	-0.129	1.000	0.125	-0.039	0.116	-0.011	0.018
CUST	MA2,2	0.013	-0.030	0.125	1.000	-0.021	0.048	-0.065	-0.074
CUST	AR1,1	0.018	-0.107	-0.039	-0.021	1.000	0.046	0.021	-0.049
GUST	AR1,2	-0.048	0.014	0.116	0.048	0.046	1.000	0.054	0.042
resl	NUM1	-0.003	0.237	-0.011	-0.065	0.021	0.054	1.000	0.273
res2	NUM2	-0.007	-0.026	0.018	-0.074	-0.049	0.042	0.273	1.000

Autocorrelation Check of Residuals

To Lag	Chi-Square	DF	Pr > ChiSq	--------------------Autocorrelations-------------------					
6	2.03	1	0.1538	0.002	-0.010	0.054	-0.036	0.011	-0.100
12	5.88	7	0.5537	0.084	0.038	-0.015	0.107	0.037	-0.069
18	7.92	13	0.8485	0.012	0.050	0.025	-0.083	0.049	-0.026
24	14.81	19	0.7343	-0.010	-0.136	-0.006	0.104	0.068	0.091

Autocorrelation Plot of Residuals

```
Lag   Covariance   Correiation   -1 9 8 7 6 5 4 3 2 1 0 1 2 3 4 5 6 7 8 9 1    Std Error

  0    20905.345      1.00000    |                    |********************|            0
  1    49.080072      0.00235    |                 .  |  .                 |     0.086387
  2     -201.438      -.00964    |                 .  |  .                 |     0.086387
  3     1121.452      0.05364    |                 .  |* .                 |     0.086395
  4     -756.628      -.03619    |                 . *|  .                 |     0.086644
  5      223.127      0.01067    |                 .  |  .                 |     0.086756
```


The ARIMA Procedure

Autocorrelation Plot of Residuals

```
Lag   Covariance   Correiation   -1 9 8 7 6 5 4 3 2 1 0 1 2 3 4 5 6 7 8 9 1    Std Error

  6    -2087.961      -.09988    |                 .**|  .                 |     0.086766
  7     1763.940      0.08438    |                 .  |** .                |     0.087620
```

8	802.131	0.03837	| . |* . |	0.088224
9	-305.981	-.01464	| . | . |	0.088349
10	2227.770	0.10656	| . |** . |	0.088367
11	763.813	0.03654	| . |* . |	0.089321
12	-1446.230	-.06918	| . *| . |	0.089432
13	252.292	0.01207	| . | . |	0.089831
14	1042.075	0.04985	| |* . |	0.089843
15	518.929	0.02482	| . | . |	0.090049
16	-1739.707	-.08322	| . **| . |	0.090100
17	1026.097	0.04908	| . |* . |	0.090672
18	-537.387	-.02571	| . *| . |	0.090870
19	-213.489	-.01021	| . | . |	0.090924
20	-2849.855	-.13632	| .***| . |	0.090932
21	-131.938	-.00631	| . | . |	0.092445
22	2173.307	0.10396	| . |** . |	0.092448
23	1416.042	0.06774	| . |* . |	0.093317
24	1911.803	0.09145	| . |** . |	0.093683

." marks two standard errors

The ARIMA Procedure

Inverse Autocorrelations

Lag	Correlation	-1 9 8 7 6 5 4 3 2 1 0 1 2 3 4 5 6 7 8 9 1
1	-0.01542	| . | . |
2	0.01107	| . | . |
3	-0.09445	| .**| . |
4	0.05022	| . |* . |
5	-0.04743	| . *| . |
6	0.09406	| . |**. |
7	-0.08819	| .**| . |
8	-0.00471	| . | . |
9	-0.02293	| * | . |
10	-0.08828	| .**| . |

3

```
  11        -0,06703    |                    . *|   .                    |
  12         0.10185    |                    .  |**.                    |
  13        -0.03357    |                    . *|   .                    |
  14         0.00865    |                    .  |   .                    |
  15        -0.01856    |                    .  |   .                    |
  16         0.08477    |                    .  |**.                    |
  17        -0.06372    |                    . *|   .                    |
  18         0.04219    |                    .  |*  .                    |
  19        -0.01219    |                    .  |   .                    |
  20         0,14453    |                    .  |***                    |
  21         0.01059    |                    .  |   .                    |
  22        -0.07962    |                    .**|   .                    |
  23        -0.10207    |                    .**|   .                    |
  24        -0,04980    |                    . *|   .                    |
```

```
                     Kentucky Power Company            12:01 Tuesday, September 3, 2002   66
                     Residential Customers

                      The ARIMA Procedure

                    Partial Autocorrelations

 Lag    Correlation    -1 9 8 7 6 5 4 3 2 1 0 1 2 3 4 5 6 7 8 9 1

   1       0.00235    |                    .  |   .                    |
   2      -0.00964    |                    .  |   .                    |
   3       0.05370    |                    .  |*  .                    |
   4      -0.03668    |                    . *|   .                    |
   5       0.01205    |                    .  |   .                    |
   6      -0.10406    |                    .**|   .                    |
   7       0.09113    |                    .  |**.                    |
   8       0.03198    |                    .  |*  .                    |
   9      -0.00060    |                    .  |   .                    |
  10       0.09157    |                    .  |**.                    |
  11       0.04008    |                    .  |*  .                    |
  12      -0.07871    |                    .**|   .                    |
  13       0.02058    |                    .  |   .                    |
  14       0.05282    |                    .  |*  .                    |
  15       0.02508    |                    .  |*  .                    |
```

4

```
16   -0.07392   |          . *|  .          |
17    0.04324   |          .  |* .          |
18   -0.05856   |          . *|  .          |
19    0.01471   |          .  |  .          |
20   -0.15272   |          ***|  .          |
21   -0.00200   |          .  |  .          |
22    0.09113   |          .  |**.          |
23    0.11433   |          .  |**.          |
24    0.05530   |          .  |* .          |
```

Model for variable CUST

Estimated Intercept 88.94732
Period(s) of Differencing 1

The ARIMA Procedure

Autoregressive Factors

Factor 1: 1 + 0.16889 B**(5) - 0.40306 B**(12)

Moving Average Factors

Factor 1: 1 + 0.30349 B**(11)
Factor 2: 1 - 0.24465 B**(1) + 0.29478 B**(13)

Input Number 1

Input Variable resl
Period(s) of Differencing 1
Overall Regression Factor -3942.37

Input Number 2

Input Variable	res2
Period(s) of Differencing	1
Overall Regression Factor	8977.875

Forecasts for variable CUST

Obs	Forecast	Std Error	95% Confidence Limits	
136	144551.9	144.59	144268.5	144835.3
137	144530.1	181.20	144174.9	144885.2
138	144525.5	211.57	144110.9	144940.2
139	144581.7	238.09	144115.0	145048.3
140	144659.4	261.95	144146.0	145172.8
141	144755.4	275.33	144215.8	145295.1
142	144825.2	289.90	144257.0	145393.4

The ARIMA Procedure

Forecasts for variable CUST

Obs	Forecast	Std Error	95% Confidence Limits	
143	144940.5	303.78	144345.1	145535.9
144	145139.2	317.05	144517.7	145760.6
145	145276.2	329.79	144629.9	145922.6
146	145321.7	343.17	144649.1	145994.3
147	145314.8	369.79	144590.1	146039.6
148	145341.1	413.62	144530.4	146151.8
149	145377.3	465.55	144464.8	146289.8
150	145416.7	512.24	144412.7	146420.7
151	145495.1	554.75	144407.8	146582.4
152	145590.1	591.67	144430.4	146749.7
153	145687.9	620.78	144471.2	146904.6
154	145778.9	647.90	144509.1	147048.8

The ARIMA Procedure

Maximum Likelihood Estimation

Parameter	Estimate	Standard Error	t Value	Approx Pr > |t|	Lag	Variable	Shift
MU	46.301 71	3.57209	12.96	<.0001	0	GUST	0
MA1,1	0.36037	0.09931	3.63	0.0003	1	CUST	0
MA2,1	0.19866	0.10690	1.86	0.0631	9	GUST	0
NUM1	1100.6	66.79094	16.48	<.0001	0	coml	0
NUM2	379.62454	67.32055	-5.64	<.0001	0	com2	0

Constant Estimate	46.30171
Variance Estimate	6144.223
Std Error Estimate	78.38509
AIC	1554.599
SBC	1569.088
Number of Residuals	134

Correlations of Parameter Estimates

Variable	Parameter	CUST MU	GUST MA1,1	CUST MA2,1	coml NUM1	com2 NUM2
GUST	MU	1.000	-0.101	-0.115	0.003	-0.013
CUST	MA1,1	-0.101	1.000	0.191	-0.034	0.004
GUST	MA2,1	-0.115	0.191	1.000	0.002	0.128
coml	NUM1	0.003	-0.034	0.002	1.000	0.318
com2	NUM2	-0.013	0.004	0.128	0.318	1.000

The ARIMA Procedure

Autocorrelation Check of Residuals

To Chi- Pr >

Lag	Square	DF	ChiSq	--------------------Autocorrelations--------------------					
6	3.41	4	0.4919	-0.027	0.027	0.127	-0.049	0.058	-0.033
12	7.98	10	0.6305	0.008	-0.127	-0.005	0.105	0.048	-0.042
18	14.59	16	0.5548	0.006	-0.082	0.093	0.041	-0.155	-0.041
24	18.44	22	0.6793	-0.071	0.088	-0.011	0.090	-0.052	0.010

Autocorrelation Plot of Residuals

```
Lag    Covariance    Correlation    -1 9 8 7 6 5 4 3 2 1 0 1 2 3 4 5 6 7 8 9 1      Std Error

  0      6144.223        1.00000    |                    |********************|              0
  1      -163.824        -.02666    |                .  *|   .                |       0.086387
  2       166.229        0.02705    |                .   |*  .                |       0.086448
  3       781.083        0.12712    |                .   |***                 |       0.086511
  4      -298.784        -.04863    |                .  *|   .                |       0.087894
  5       355.746        0.05790    |                .   |*  .                |       0.088095
  6      -203.973        -.03320    |                .  *|   .                |       0.088378
  7     47.150395        0.00767    |                .   |   .                |       0.088471
  8      -778.805        -.12675    |                .***|   .                |       0.088476
  9    -28.980855        -.00472    |                .   |   .                |       0.089821
 10       648.175        0.10549    |                .   |** .                |       0.089823
 11       295.311        0.04806    |                .   |*  .                |       0.090743
 12      -257.049        -.04184    |                .  *|   .                |       0.090933
 13     37.137377        0.00604    |                .   |   .                |       0.091076
 14      -504.368        -.08209    |                . **|   .                |       0.091079
 15       569.885        0.09275    |                .   |** .                |       0.091630
 16       249.726        0.04064    |                .   |*  .                |       0.092328
 17      -952.909        -.15509    |                .***|   .                |       0.092461
 18      -249.509        -.04061    |                .  *|   .                |       0.094383
 19      -436.673        -.07107    |                .  *|   .                |       0.094513
 20       541.363        0.08811    |                .   |** .                |       0.094911
```

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Commercial Customers

The ARIMA Procedure

Autocorrelation Plot of Residuals

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```
Lag    Covariance    Correlation    -1 9 8 7 6 5 4 3 2 1 0 1 2 3 4 5 6 7 8 9 1    Std Error

 21    68.110671       -.01109      |                    .  |  .                |    0.095519
 22    555.768         0.09045      |                    .  |** .               |    0.095529
 23    -320.154        -.05211      |                    . *|  .                |    0.096166
 24    60.473933       0.00984      |                    .  |  .                |    0.096377

                    "." marks two standard errors
```

Inverse Autocorrelations

```
Lag    Correlation    -1 9 8 7 6 5 4 3 2 1 0 1 2 3 4 5 6 7 8 9 1

  1      -0.01660      |                    .  |  .                |
  2      -0.04196      |                    . *|  .                |
  3      -0.22123      |                  ****|  .                |
  4       0.08761      |                    .  |**.                |
  5      -0.02449      |                    .  |  .                |
  6       0.04700      |                    .  |* .                |
  7      -0.06047      |                    . *|  .                |
  8       0.11026      |                    .  |**.                |
  9       0.02883      |                    .  |* .                |
 10      -0.07902      |                    .**|  .                |
 11      -0.07822      |                    .**|  .                |
 12       0.04331      |                    .  |* .                |
 13       0.05714      |                    .  |* .                |
 14       0.02508      |                    .  |* .                |
 15      -0.08913      |                    .**|  .                |
 16      -0.07630      |                    .**|  .                |
 17       0.16089      |                    .  |***                |
 18       0.04365      |                    .  |* .                |
 19       0.06469      |                    .  |* .                |
 20      -0.10796      |                    .**|  .                |
```


6

Inverse Autocorrelations

```
Lag    Correlation    -1 9 8 7 6 5 4 3 2 1 0 1 2 3 4 5 6 7 8 9 1

 21        0.02180    |                    .  |  .                 |
 22       -0.07888    |                   .**|  .                  |
 23        0.05351    |                    .  |* .                 |
 24       -0.04613    |                    . *|  .                 |
```

Partial Autocorrelations

```
Lag    Correlation    -1 9 8 7 6 5 4 3 2 1 0 1 2 3 4 5 6 7 8 9 1

  1       -0.02666    |                    . *|  .                 |
  2        0.02636    |                    .  |* .                 |
  3        0.12871    |                    .  |***                 |
  4       -0.04304    |                    . *|  .                 |
  5        0.04918    |                    .  |* .                 |
  6       -0.04531    |                    . *|  .                 |
  7        0.01514    |                    .  |  .                 |
  8       -0.14357    |                    ***|  .                 |
  9        0.00514    |                    .  |  .                 |
 10        0.10589    |                    .  |**.                 |
 11        0.09833    |                    .  |**.                 |
 12       -0.06324    |                    . *|  .                 |
 13       -0.01342    |                    .  |  .                 |
 14       -0.10651    |                    .**|  .                 |
 15        0.10842    |                    .  |**.                 |
 16        0.02762    |                    .  |* .                 |
 17       -0.13270    |                    ***|  .                 |
 18       -0.06918    |                    . *|  .                 |
 19       -0.03341    |                    . *|  .                 |
 20        0.10509    |                    .  |**.                 |
 21       -0.01266    |                    .  |  .                 |
 22        0.09771    |                    .  |**.                 |
```


The ARIMA Procedure

Partial Autocorrelations

```
Lag    Correlation    -1 9 8 7 6 5 4 3 2 1 0 1 2 3 4 5 6 7 8 9 1

 23      -0.06321     |                   . *|  .                  |
 24       0.05373     |                   .  |* .                  |
```

Model for variable CUST

Estimated Intercept	46.30171
Period(s) of Differencing	1

Moving Average Factors

Factor 1: 1 - 0.36037 B**(1)
Factor 2: 1 - 0.19866 B**(9)

Input Number 1

Input Variable	coml
Period(s) of Differencing	1
Overall Regression Factor	1100.582

Input Number 2

Input Variable	com2
Period(s) of Differencing	1
Overall Regression Factor	-379.625

The ARIMA Procedure

Forecasts for variable CUST

Obs	Forecast	Std Error	95% Confidence Limits

136	26846.7678	78.385:	26693.1358	27000.3998
137	26893.0634	93.0485	26710.6917	27075.4350
138	26928.6525	105.6968	26721.4906	27135.8144
139	26973.5146	116.9855	26744.2272	27202.8019
140	27010.7987	127.2769	26761.3407	27260.2568
141	27045.9545	136.7962	26777.8389	27314.0701
142	27080.2939	145.6948	26794.7373	27365.8506
143	27140.2068	154.0804	26838.2147	27442.1989
144	27089.9204	162.0326	26772.3423	27407.4986
145	27170.0753	165.6784	26845.3515	27494.7991
146	27216.3770	170.4804	26882.2417	27550.5124
147	27262.6787	175.1507	26919.3897	27605.9677
148	27308.9805	179.6996	26956.7756	27661.1853
149	27355.2822	184.1363	26994.3817	27716.1826
150	27401.5839	188.4685	27032.1924	27770.9754
151	27447.8856	192.7034	27070.1940	27825.5772
152	27494.1873	196.8471	27108.3740	27880.0006
153	27540.4890	200.9054	27146.7216	27934.2565
154	27586.7907	204.8834	27185.2267	27988.3548

The ARIMA Procedure

Maximum Likelihood Estimation

Parameter	Estimate	Standard Error	t Value	Approx Pr > |t|	Lag	Variable	Shift
MU	16.61078	6.44290	2.58	0.0099	0	USAGE	0
MA1,1	-0.23974	0.09216	-2.60	0.0093	1	USAGE	0
MA2,1	0.20027	0.09395	2.13	0.0330	8	USAGE	0
AR1,1	-0.42411	0.08289	-5.12	<.0001	12	USAGE	0
NUM1	0.79142	0.20811	3.80	0.0001	0	bcdd65	0
NUM2	1.18277	0.10122	11.68	<.0001	0	bhdd55	0

Constant Estimate	23.65558
Variance Estimate	9817.613
Std Error Estimate	99.08387
AIC	1500.301
SBC	1517.223
Number of Residuals	124

Correlations of Parameter Estimates

Variable		USAGE	USAGE	USAGE	USAGE	bcdd65	bhdd55
Parameter		MU	MA1,1	MA2,1	AR1,1	NUM?	NUM2
USAGE	MU	1.000	0.025	-0.038	-0.003	0.094	-0.016
USAGE	MA1,1	0.025	1.000	-0.102	0.043	0.254	0.088
USAGE	MA2,1	-0.038	-0.102	1.000	0.114	-0.156	0.140
USAGE	AR1,1	-0.003	0.043	0.114	1.000	-0.042	0.051
bcdd65	NUM1	0.094	0.254	-0.156	-0.042	1.000	0.062
bhdd55	NUM2	-0.016	0.088	0.140	0.051	0.062	1.000

The ARIMA Procedure

Autocorrelation Check of Residuals

To Lag	Chi-Square	DF	Pr > ChiSq	Autocorrelations					
6	3.80	3	0.2835	-0.026	-0.095	0.053	0.121	0.039	-0.024
12	8.62	9	0.4731	0.100	0.005	-0.064	-0.066	0.063	-0.113
18	9.38	15	0.8569	0.041	0.008	-0.040	0.017	0.024	-0.032
24	20.18	21	0.5100	-0.136	0.026	-0.045	-0.035	-0.078	-0.204

Autocorrelation Plot of Residuals

```
Lag  Covariance   Correlation  -1 9 8 7 6 5 4 3 2 1 0 1 2 3 4 5 6 7 8 9 1   Std Error

 0   9817.613     1.00000     |                    ....................|   0
 1   -253.921     -.02586     |                  .  *|  .              |   0.089803
 2   -937.357     -.09548     |                  . **|  .              |   0.089863
 3   515.96:      0.05255     |                  .   |*  .             |   0.090677
 4   1191.115     0.12132     |                  .   |**  .            |   0.090922
 5   385.983      0.03932     |                  .   |*  .             |   0.092219
 6   -232.929     -.02373     |                  .   |   .             |   0.092354
 7   978.157      0.09963     |                  .   |**  .            |   0.092403
 8   46.547684    0.00474     |                  .   |   .             |   0.093265
 9   -629.328     -.06410     |                  .  *|   .             |   0.093267
10   -652.062     -.06642     |                  .  *|   .             |   0.093622
11   619.630      0.06311     |                  .   |*  .             |   0.094001
12   -1107.194    -.11278     |                  . **|   .             |   0.094342
13   402.370      0.04098     |                  .   |*  .             |   0.095423
14   75.165442    0.00766     |                  .   |   .             |   0.095565
15   -395.299     -.04026     |                  .  *|   .             |   0.095570
16   169.674      0.01728     |                  .   |   .             |   0.095707
17   237.310      0.02417     |                  .   |   .             |   0.095732
18   -317.096     -.03230     |                  .  *|   .             |   0.095781
19   -1335.903    -.13607     |                  .***|   .             |   0.095869
20   252.751      0.02574     |                  .   |*  .             |   0.097414
21   -441.001     -.04492     |                  .  *|   .             |   0.097469
```

Autocorrelation Plot of Residuals

Lag	Covariance	Correlation	-1 9 8 7 6 5 4 3 2 1 0 1 2 3 4 5 6 7 8 9 1	Std Error
22	-344.531	-.03509	| . *| . |	0.097636
23	-770.634	-.07850	| .**| . |	0.097737
24	2002.049	-.20392	| ****| . |	0.098244

"." marks two standard errors

Inverse Autocorrelations

Lag	Correlation	-1 9 8 7 6 5 4 3 2 1 0 1 2 3 4 5 6 7 8 9 1
1	0.06412	| . |* . |
2	0.10966	| . |** . |
3	0.00903	| . | . |
4	-0.10826	| .**| . |
5	-0.09227	| .**| . |
6	-0.01327	| . | . |
7	-0.10472	| .**| . |
8	-0.03332	| . *| . |
9	0.10794	| . |** . |
10	0.11634	| . |** . |
11	-0.02323	| . | . |
12	0.18313	| . |**** |
13	-0.03980	| . *| . |
14	0.00504	| . | . |
15	0.00611	| . | . |
16	-0.06510	| . *| . |
17	-0.07936	| .**| . |
18	0.02193	| . | . |
19	0.07067	| . |* . |
20	-0.02826	| . *| . |
21	0.07823	| . |** . |
22	0.07442	| . |* . |

```
                         The ARIMA Procedure

                       Inverse Autocorrelations

 Lag    Correlation    -1 9 8 7 6 5 4 3 2 1 0 1 2 3 4 5 6 7 8 9 1

  23       0.056?6     |                    .  |* .                |
  24       0.204?4     |                    .  |***                |


                       Partial Autocorrelations

 Lag    Correlation    -1 9 8 7 6 5 4 3 2 1 0 1 2 3 4 5 6 7 8 9 1

   1      -0.02586     |                    .  *|  .               |
   2      -0.09621     |                    . **|  .               |
   3       0.04783     |                    .   |* .               |
   4       0.11617     |                    .   |**.               |
   5       0.05655     |                    .   |* .               |
   6      -0.00205     |                    .   |  .               |
   7       0.09740     |                    .   |**.               |
   8      -0.01039     |                    .   |  .               |
   9      -0.05939     |                    .  *|  .               |
  10      -0.08416     |                    . **|  .               |
  11       0.02687     |                    .   |* .               |
  12      -0.13232     |                    .***|  .               |
  13       0.06896     |                    .   |* .               |
  14      -0.00050     |                    .   |  .               |
  15      -0.01952     |                    .   |  .               |
  16       0.04673     |                    .   |* .               |
  17       0.04108     |                    .   |* .               |
  18      -0.04868     |                    .  *|  .               |
  19      -0.12190     |                    . **|  .               |
  20      -0.00716     |                    .   |  .               |
  21      -0.09225     |                    . **|  .               |
  22      -0.03118     |                    .  *|  .               |
  23      -0.04694     |                    .  *|  .               |
  24      -0.24270     |                  *****|                  |
```
Residential

```
                    The ARIMA Procedure

                 Model for variable USAGE

          Estimated Intercept          16 6107
          Period(s) of Differencing          12

                  Autoregressive Factors

             Factor 1:  1 + 0.42411 B**(12)

                  Moving Average Factors

             Factor 1:  1 + 0.23974 B**(1)
             Factor 2:  1 - 0.20027 B**(8)

                      Input Number 1

          Input Variable                bcdd65
          Period(s) of Differencing         12
          Overall Regression Factor   0 791421

                      Input Number 2

          Input Variable                bhdd55
          Period(s) of Differencing         12
          Overall Regression Factor   1 182774

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                    The ARIMA Procedure

                 Forecasts for variable USAGE

Obs       Forecast    Std Error       95% Confidence Limits
```

137	1004.4843	99.0839	810.2835	1198.6851
138	1050.8249	101.8914	851.1213	1250.5284
139	1241.5593	101.8914	1041.8558	1441.2629
140	1303.7374	101.8914	1104.0339	1503.4410
141	1238.6598	101.8914	1038.9563	1438.3634
142	1006.6066	101.8914	806.9031	1206.3102
143	1128.0507	101.8914	928.3471	1327.7542
144	1657.2484	101.8914	1457.5449	1856.9520
145	2159.2209	103.8058	1955.7654	2362.6765
146	1876.7720	103.9147	1673.1029	2080.4411
147	1622.3187	103.9147	1418.6496	1825.9878
148	1291.5755	103.9147	1087.9064	1495.2446
149	1011.6867	118.5507	779.3315	1244.0418
150	1059.3256	119.3374	825.4286	1293.2225
151	1260.8756	119.3374	1026.9786	1494.7725
152	1322.9403	119.3374	1089.0434	1556.8373
153	1255.0691	119.3374	1021.1721	1488.9660
154	1023.5301	119.3374	789.6332	1257.4271
155	1167.1563	119.3374	933.2594	1401.0532

The ARIMA Procedure

Maximum Likelihood Estimation

Parameter	Estimate	Standard Error	t Value	Approx Pr > |t|	Lag	Variable	Shift
MU	15.57673	15.97106	0.98	0.3294	0	USAGE	0
AR1,1	-0.37294	0.08568	-4.35	<.0001	12	USAGE	0
NUM1	1.46231	0.43846	3.34	0.0009	0	bcdd65	0
NUM2	1.26185	0.24208	5.21	<.0001	0	bhdd55	0
NUM3	727.20192	197.06110	3.69	0.0002	0	coml	0
NUM4	652.58362	135.54705	4.81	<.0001	0	com2	0

Constant Estimate	21.3859
Variance Estimate	56782.46
Std Error Estimate	238.2907

AIC	1716.97
SBC	1733.891
Number of Residuals	124

Correlations of Parameter Estimates

Variable		USAGE	USAGE	bcdd65	bhdd55	com1	com2
Parameter		MU	AR1,1	NUM1	NUM2	NUM3	NUM4
USAGE	MU	1.000	-0.026	0.093	-0.012	0.001	0.003
USAGE	AR1,1	0.026	1.000	-0.123	-0.003	0.073	-0.076
bcdd65	NUM1	0.093	-0.123	1.000	0.010	-0.011	0.024
bhdd55	NUM2	0.012	-0.003	.010	1.000	-0.233	0.008
com1	NUM3	0.001	0.073	.011	-0.233	1.000	-0.007
com2	NUM4	0.003	-0.076	0.024	0.008	-0.007	1.000

The ARIMA Procedure

Autocorrelation Check of Residuals

To Lag	Chi-Square	DF	Pr > ChiSq	Autocorrelations					
6	5.88	5	0.3176	0.131	0.056	0.095	0.108	0.021	0.066
12	9.69	11	0.5588	0.032	-0.067	-0.039	0.120	0.033	-0.073
18	14.06	17	0.6629	-0.093	-0.058	-0.062	-0.032	-0.075	-0.089
24	28.77	23	0.1882	-0.071	-0.021	-0.136	-0.124	-0.062	-0.228

Autocorrelation Plot of Residuals

```
Lag    Covariance    Correlation    1 9 8 7 6 5 4 3 2 1 0 1 2 3 4 5 6 7 8 9 1      Std Error

  0     56782.460        1.00000    |                    |********************|           0
  1      7420.792        0.13068    |                  . |***                 |    0.089803
  2      3203.267        0.05641    |                  . |*  .                |    0.091324
  3      5399.085        0.09508    |                  . |** .                |    0.091604
  4      6114.846        0.10769    |                  . |**                  |    0.092397
```

```
  5      1199.006     0.02112   |                    .    |    .                    |    0.093403
  6      3731.955     0.06572   |                    .    |*   .                    |    0.093442
  7      1813.979     0.03195   |                    .    |*   .                    |    0.093814
  8     -3812.123     -.06714   |                    .   *|    .                    |    0.093902
  9     -2191.183     -.03859   |                    .   *|    .                    |    0.094288
 10      6788.550     0.11955   |                    .    |**  .                    |    9.094415
 11      1893.553     0.03335   |                    .    |*   .                    |    0.095628
 12     -4143.018     -.07296   |                    .   *|    .                    |    0.095722
 13     -5292.891     -.09321   |                    .  **|    .                    |    0.096169
 14     -3317.063     -.05842   |                    .   *|    .                    |    0.096895
 15     -3497.730     -.06160   |                    .   *|    .                    |    0.097179
 16     -1810.777     -.03189   |                    .   *|    .                    |    0.097493
 17     -4242.782     -.07472   |                    .   *|    .                    |    0.097577
 18     -5036.928     -.08871   |                    .  **|    .                    |    0.098038
 19     -4039.157     -.07113   |                    .   *|    .                    |    0.098683
 20     -1188.526     -.02093   |                    .    |    .                    |    0.099096
 21     -7721.682     -.13599   |                    . ***|    .                    |    0.099131
```


The ARIMA Procedure

Autocorrelation Plot of Residuals

```
Lag   Covariance    Correlation   -1 9 8 7 6 5 4 3 2 1 0 1 2 3 4 5 6 7 8 9 1    Std Error

 22    -7069.351     -.12450   |                    .  **|    .                    |    0.100624
 23    -3503.021     -.06169   |                    .   *|    .                    |    0.101859
 24   -12945.470     -.22798   |                    *****|    .                    |    0.102160
```

"." marks two standard errors

Inverse Autocorrelations

```
Lag    Correlation    -1 9 8 7 6 5 4 3 2 1 0 1 2 3 4 5 6 7 8 9 1

  1     -0.06378     |                    .   *|    .                    |
  2     -0.02547     |                    .   *|    .                    |
  3     -0.01793     |                    .    |    .                    |
  4     -0.05017     |                    .   *|    .                    |
```

```
  5      0.02788     |                   .   |*   .                  |
  6     -0.02538     |                   .  *|    .                  |
  7      0.00821     |                   .   |    .                  |
  8      0.09380     |                   .   |**  .                  |
  9      0.07466     |                   .   |*   .                  |
 10     -0.10860     |                   . **|    .                  |
 11     -0.05133     |                   .  *|    .                  |
 12      0.05354     |                   .   |*   .                  |
 13      0.08078     |                   .   |**  .                  |
 14     -0.00095     |                   .   |    .                  |
 15      0.02559     |                   .   |*   .                  |
 16      0.02709     |                   .   |*   .                  |
 17      0.03397     |                   .   |*   .                  |
 18     -0.00722     |                   .   |    .                  |
 19      0.00776     |                   .   |    .                  |
 20     -0.04147     |                   .  *|    .                  |
 21      0.09368     |                   .   |**  .                  |
 22      0.06608     |                   .   |*   .                  |
                          Commercial                    12:01 Tuesday, September 3, 2002  41

                                  The ARIMA Procedure

                               Inverse Autocorrelations

Lag    Correlation    -1 9 8 7 6 5 4 3 2 1 0 1 2 3 4 5 6 7 8 9 1

 23     -0.03173     |                   .  *|    .                  |
 24      0.17369     |                   .   |***.                   |


                               Partial Autocorrelations

Lag    Correlation    -1 9 8 7 6 5 4 3 2 1 0 1 2 3 4 5 6 7 8 9 1

  1      0.13069     |                   .   |***.                   |
  2      0.04002     |                       |*                      |
  3      0.08435     |                   .   |**  .                  |
  4      0.08559     |                   .   |**  .                  |
  5     -0.00948     |                   .   |    .                  |
  6      0.05129     |                   .   |*   .                  |
```

```
  7     0.00239   |                .      |     .                 |
  8    -0.08784   |                .    **|     .                 |
  9    -0.03282   |                .     *|     .                 |
 10     0.12490   |                .      |**   .                 |
 11     0.01729   |                .      |     .                 |
 12    -0.07539   |                .    **|     .                 |
 13    -0.09689   |                .    **|     .                 |
 14    -0.05214   |                .     *|     .                 |
 15    -0.03002   |                .     *|     .                 |
 16    -0.00697   |                .      |     .                 |
 17    -0.05796   |                .     *|     .                 |
 18    -0.03502   |                .     *|     .                 |
 19    -0.01554   |                .      |     .                 |
 20    -0.00809   |                .      |     .                 |
 21    -0.14092   |                .   ***|     .                 |
 22    -0.08475   |                .    **|     .                 |
 23     0.00183   |                .      |     .                 |
 24    -0.19437   |                   ****|     .                 |
```


The ARIMA Procedure

Model for variable USAGE

Estimated intercept	15.57673
Period(s) of Differencing	12

Autoregressive Factors

Factor 1: 1 + 0.37294 B**(12)

Input Number 1

Input Variable	bcdd65
Period(s) of Differencing	12
Overall. Regression Factor	1.462314

Input Number 2

Input Variable	bhdd55
Period(s) of Differencing	12
Overall. Regression Factor	1.261855

Input Number 3

Input Variable	com1
Period(s) of Differencing	12
Overall Regression Factor	727.2019

Input Number 4

Input Variable	com2
Period(s) of Differencing	12
Overall Regression Factor	652.5836

The ARIMA Procedure

Forecasts for variable USAGE

Obs	Forecast	Std Error	95% Confidence Limits	
137	3718.5223	238.2907	3251.4811	4185.5635
138	4026.0878	238.2907	3559.0466	4493.1290
139	4304.2260	238.2907	3837.1848	4771.2672
140	4404.2448	238.2907	3937.2036	4871.2860
141	4420.6949	238.2907	3953.6537	4887.7361
142	3744.5496	238.2907	3277.5084	4211.5908
143	3663.2897	238.2907	3196.2485	4130.3309
144	4288.3473	238.2907	3821,3061	4755.3885
145	4821.0661	238.2907	4354.0249	5288.1073
146	4364.6982	238.2907	3897.6570	4831.7394
147	4039.3229	238.2907	3572.2817	4506.3641
148	3850.2495	238.2907	3383.2083	4317.2907
149	3746.5260	281.2644	3195.2580	4297.7940

150	4016.0868	281.2644	3464.8188	4567.3548
151	4324.5436	281.2644	3773.2756	4875.8116
152	4413.2767	281.2644	3862.0087	4964.5447
153	4420.6367	281.2644	3869.3687	4971.9047
154	3747.2352	281.2644	3195.9672	4298.5032
155	3685.6892	281.2644	3134.4212	4236.9572

The ARIMA Procedure

Maximum Likelihood Estimation

Parameter	Estimate	Standard Error	t Value	Approx Pr > |t|	Lag	Variable	Shift
MU	238712.3	185128.1	1.29	0.1972	0	KWH	0
MA1,1	0.80970	0.06900	11.73	<.0001	2	KWH	0
AR1,1	-0.82518	0.06558	-12.58	<.0001	1	KWH	0
AR2,1	0.42751	0.08055	5.31	<.0001	12	KWH	0
NUM1	-76207714	7192240.1	-10.60	<.0001	0	ind1	0
NUM2	86414097	7093480.6	12.18	<.0001	0	ind2	0
NUM3	-32144313	7665401.4	-4.19	<.0001	0	ind3	0

Constant Estimate	249429.7
Variance Estimate	1.424E14
Std Error Estimate	11934267
AIC	4793.222
SBC	4813.559
Number of Residuals	135

Correlations of Parameter Estimates

Variable	Parameter	KWH MU	KWH MA1,1	KWH AR1,1	KWH AR2,1	ind1 NUM1	ind2 NUM2	ind3 NUM3
KWH	MU	1.000	-0.002	-0.001	-0.007	0.000	-0.000	-0.000
KWH	MA1,1	-0.002	1.000	-0.655	0.127	0.007	0.029	-0.000
KWH	AR1,1	-0.001	-0.655	1.000	0.018	-0.015	-0.013	0.003

KWH	AR2,1	-0.007	3.127	0.018	1.000	-0.055	0.032	0.088
ind1	NUM1	0.000	0.007	-0.015	-0.055	1.000	0.163	-0.168
ind2	NUM2	-0.000	0.029	-0.013	0.032	0.163	1.000	-0.025
ind3	NUM3	-0.000	-0.000	0.003	0.088	-0.168	-0.025	1.000

The ARIMA Procedure

Autocorrelation Check of Residuals

To Lag	Chi-Square	DF	Pr > ChiSq	--------------------Autocorrelations--------------------					
6	4.03	3	0.2583	0.122	0.043	-0.050	0.012	-0.046	-0.085
12	11.37	9	0.2514	-0.095	-0.010	0.003	0.068	-0.166	-0.090
18	15.65	15	0.4060	0.078	0.1'2	0.010	-0.014	-0.064	-0.069
24	26.22	21	0.1982	-0.041	-0.116	3.023	0.065	0.192	0.089

Autocorrelation Plot of Residuals

```
Lag   Covariance    Correlation   -1 9 8 7 6 5 4 3 2 1 0 1 2 3 4 5 6 7 8 9 1      Std Error

  0   1.42427E14       1.00000    |                    |********************|             0
  1   1.74318E13       0.12239    |                .   |**.                 |      0.086066
  2   6.06603E12       0.04259    |                .   |* .                 |      0.087346
  3   -7.1366E12       -.05011    |                . * |  .                 |      0.087500
  4   1.67375E12       0.01175    |               .    |   .                |      0.087712
  5   -6.5978E12       -,04632    |               .  * |   .                |      0.087724
  6    -1.209E13       -.08488    |               . ** |   .                |      0.087905
  7   -1.3468E13       -.09456    |               . ** |   .                |      0.088510
  8   -1.4454E12       -.01015    |               .    |   .                |      0.089255
  9    3.9372E11       0.00276    |               .    |   .                |      0.089263
 10    9.6321E12       0.06763    |               .    |*  .                |      0.089264
 11   -2.3711E13       -,16648    |               .*** |   .                |      0.089643
 12   -1.2824E13       -.09004    |               . ** |   .                |      0.091904
 13   1.10971E13       0.07791    |               .    |** .                |      0.092556
 14   1.59469E13       0.11197    |               .    |** .                |      0.093040
 15    1.4153E12       0.00994    |               .    |   .                |      0.094033
 16   -1.9547E12       -.01372    |               .    |   .                |      0.094041
```

```
  17    -9.0828E12      -.06377   |              .  *|   .              |     0.094056
  18    -9.8756E12      -.06934   |              .  *|   .              |     0.094375
  19    -5.7812E12      -.04059   |              .  *|   .              |     0.094752
  20    -1.6468E13      -.11562   |              . **|   .              |     0.094881
  21    3.21692E12      0.02259   |              .   |   .              |     0.095919
```


The ARIMA Procedure

Autocorrelation Plot of Residuals

```
 Lag    Covariance    Correlation  -1 9 8 7 6 5 4 3 2 1 0 1 2 3 4 5 6 7 8 9 1     Std Error

  22    9.24045E12      0.06488   |              .   |*  .              |     0.095958
  23    2.73059E13      0.19172   |              .   |****              |     0.096282
  24     1.2675E13      0.08899   |              .   |** .              |     0.099070
```

"." marks two standard errors

Inverse Autocorrelations

```
 Lag    Correlation  -1 9 8 7 6 5 4 3 2 1 0 1 2 3 4 5 6 7 8 9 1

   1     -0.08016   |               .**|   .               |
   2     -0.05206   |               . *|   .               |
   3      0.02455   |               .  |   .               |
   4     -0.05253   |               . *|   .               |
   5      0.02276   |               .  |   .               |
   6      0.07750   |               .  |**.               |
   7      0.03386   |               .  |*  .               |
   8      0.01261   |               .  |   .               |
   9      0.04620   |               .  |*  .               |
  10     -0.11841   |               .**|   .               |
  11      0.16619   |               .  |***               |
  12      0.06809   |               .  |*  .               |
  13     -0.06737   |               . *|   .               |
  14     -0.05590   |               . *|   .               |
  15      0.00309   |               .  |   .               |
  16     -0.03670   |               . *|   .               |
```

```
17      0.04662     |                 .  |*  .                    |
18      0.05405     |                 .  |*  .                    |
19      0.00400     |                 .  |   .                    |
20      0.09548     |                 .  |** .                    |
21      0.06565     |                 . *|   .                    |
22      0.01598     |                 .  |   .                    |
                         Industrial                  12:01 Tuesday, September 3, 2002  47

                        The ARIMA Procedure

                     Inverse Autocorrelations

Lag    Correlation    -1 9 8 7 6 5 4 3 2 1 0 1 2 3 4 5 6 7 8 9 1

23     0 .09050     |                 .**|   .                    |
24     0 .04151     |                 . *|   .                    |


                     Partial Autocorrelations

Lag    Correlation    -1 9 8 7 6 5 4 3 2 1 0 1 2 3 4 5 6 7 8 9 1

 1      0 12239     |                 .  |** .                    |
 2      0 02803     |                 .  |*  .                    |
 3      0 05984     |                 . *|   .                    |
 4      0 02405     |                 .  |   .                    |
 5      0 04726     |                 . *|   .                    |
 6      0 07984     |                 .**|   .                    |
 7      0 07111     |                 . *|   .                    |
 8      0 01031     |                 .  |   .                    |
 9      0 00183     |                 .  |   .                    |
10      0 06105     |                 .  |*  .                    |
11      0.19109     |               * ***|   .                    |
12      0 06988     |                 . *|   .                    |
13      0 11291     |                 .  |** .                    |
14      0 07540     |                 .  |** .                    |
15      0 01992     |                 .  |   .                    |
16      0.01929     |                 .  |   .                    |
17      0 08512     |                 .**|   .                    |
18      0 09947     |                 .**|   .                    |
```

```
19        -0.00491   |                .  |  .              |
20        -0.09267   |                .**|  .              |
21         0.09049   |                .  |**.              |
22         0.04493   |                .  |* .              |
23         0.11159   |                .  |**.              |
24         0.04690   |                .  |* .              |
```

```
                    The ARIMA Procedure

                 Model for variable KWH

        Estimated Intercept          23[illegible]712 3
        Period(s) of Differencing             1


                 Autoregressive Factors

          Factor 1:  1 + 0.82518 B**(1)
          Factor 2:  1 - 0.42751 B**(12)


                 Moving Average Factors

           Factor 1:  1   0 [illegible]0[illegible]7 B**(2)


                    Input Number 1

        Input Variable                     ind1
        Period(s) of Differencing             1
        Overall Regression Factor      7.621E7


                    Input Number 2

        Input Variable                     ind2
        Period(s) of Differencing             1
        Overall Regression Factor    [illegible]6414097
```

Input Number 3

Input Variable	ind3
Period(s) of Differencing	1
Overall Regression Factor	-3.214E7

The ARIMA Procedure

Forecasts for variable KWH

Obs	Forecast	Std Error	95% Confidence Limits	
137	266352828	11934267	242962095	289743561
138	265783205	12115266	242037720	289528689
139	264275811	12127721	240505915	288045708
140	265491079	12263182	241455684	289526474
141	260405405	12287408	236322528	284488283
142	265082811	12395676	240787732	289377891
143	268226490	12429932	243864271	292588709
144	269322882	12521335	244781516	293864248
145	274003574	12563216	249380123	298627025
146	268563532	12643814	243782112	293344951
147	268969552	12691138	244095379	293843725
148	271617390	12764611	246599212	296635567
149	269395068	14210238	241543513	297246624
150	269205342	14382635	241015895	297394789
151	268765957	14451585	240441372	297090542
152	269365731	14600299	240749671	297981791
153	267374777	14679921	238602660	296146895
154	269472653	14813132	240439447	298505859
155	270984972	14899987	241781533	300188410

The ARIMA Procedure

Maximum Likelihood Estimation

Standard Approx

Parameter	Estimate	Error	t Value	Pr > |t|	Lag	Variable	Shift
MU	17537.7	873.43423	20.08	<.0001	0	KWH	0
MA1,1	0.82810	0.11004	7.53	<.0001	12	KWH	0
AR1,1	0.41381	0.08100	5.11	<.0001	1	KWH	0
AR1,2	0.05316	0.08875	0.60	0.5492	3	KWH	0
AR1,3	-0.17910	0.08956	-2.00	0.0455	4	KWH	0
NUM1	64424.6	11623.4	5.54	<.0001	0	or1	0

Constant Estimate	12489.I1
Variance Estimate	5.1343E8
Std Error Estimate	22659.07
AIC	2858.784
SBC	2875.705
Number of Residuals	124

Correlations of Parameter Estimates

Variable	Parameter	KWH MU	KWH MA1,1	KWH ARI,1	KWH AR1,2	KWH AR1,3	or1 NUM1
KWH	MU	1.000	-0.060	-0.013	0.000	0.009	0.002
KWH	MA1,1	-0.060	1.000	0.057	-0.001	-0.130	-0.018
KWH	ARI,1	-0.013	0.057	1.000	-0.244	0.025	-0.106
KWH	ARI,2	0.000	-0.001	-0.244	1.000	-0.414	-0.040
KWH	AR1,3	0.009	-0.130	0.025	-0.414	1.000	0.000
or1	NUMl	0.002	-0.018	-0.106	-0.040	0.000	1.000

The ARIMA Procedure

Autocorrelation Check of Residuals

To Lag	Chi-Square	DF	Pr > ChiSq	--------------------Autocorrelations--------------------					
6	4.36	2	0.1131	-0.076	0.135	0.010	-0.001	-0.082	-0.055
12	10.78	8	0.2143	0.104	-0.142	0.051	-0.092	0.043	-0.058

18	16.79	14	0.2677	0.146	-0.066	-0.006	-0.028	-0.123	-0.022
24	23.98	20	0.2431	-0.146	0.096	-0.063	0.013	-0.112	0.026

Autocorrelation Plot of Residuals

```
Lag   Covariance   Correlation   -1 9 8 7 6 5 4 3 2 1 0 1 2 3 4 5 6 7 8 9 1   Std Error

  0    513433519       1.00000   |                    |....................|           0
  1    -39091904       -.07614   |                 . **|    .                |    0.089803
  2     69290121       0.13495   |                 .   |***.                |    0.090322
  3      4890742       0.00953   |                 .   |    .                |    0.091934
  4      -741409       -.00144   |                 .   |    .                |    0.091941
  5    -42147307       -.08209   |                 . **|    .                |    0.091942
  6    -28001559       -.05454   |                 .  *|    .                |    0.092531
  7     53265169       0.10374   |                 .   |**  .                |    0.092790
  8    -73161306       -.14249   |                 .***|    .                |    0.093720
  9     26428673       0.05147   |                 .   |*   .                |    0.095452
 10    -47309830       -,09214   |                 . **|    .                |    0.095675
 11     22286601       0.04341   |                 .   |*   .                |    0.096388
 12    -29728012       -.05790   |                 .  *|    .                |    0.096546
 13     74751789       0.14559   |                 .   |***.                |    0.096825
 14    -33656929       -.06555   |                 .  *|    .                |    0.098575
 15     -3169416       -,00617   |                 .   |    .                |    0.098926
 16    -14210989       -.02768   |                 .  *|    .                |    0.098929
 17    -63331092       -.12335   |                 . **|    .                |    0.098992
 18    -11305424       -.02202   |                 .   |    .                |    0.100223
 19    -74787831       -.14566   |                 .***|    .                |    0.100262
 20     49116891       0.09566   |                 .   |**  .                |    0.101955
 21    -32144152       -.06261   |                 .  *|    .                |    0.102676
```


The ARIMA Procedure

Autocorrelation Plot of Residuals

```
Lag   Covariance   Correlation   -1 9 8 7 6 5 4 3 2 1 0 1 2 3 4 5 6 7 8 9 1   Std Error

 22      6520482       0.01270   |                 .   |    .                |    0.102983
 23    -57502348       -.11200   |                 . **|    .                |    0.102996
```

```
   24      13286440      0.02588    |                 .  |*  .                 |      0.103974

                            "." marks two standard errors


                              Inverse Autocorrelations

       Lag    Correlation    -1 9 8 7 6 5 4 3 2 1 0 1 2 3 4 5 6 7 8 9 1

         1        0.05439    |                 .  |*  .                 |
         2       -0.11259    |                 . **|   .                 |
         3       -0.06171    |                 .  *|   .                 |
         4        0.05110    |                 .  |*  .                 |
         5        0.11755    |                 .  |** .                 |
         6        0.05756    |                 .  |*  .                 |
         7       -0.08744    |                 . **|   .                 |
         8        0.09153    |                 .  |** .                 |
         9        0.04011    |                 .  |*  .                 |
        10        0.04507    |                 .  |*  .                 |
        11        0.02387    |                 .  |   .                 |
        12       -0.01025    |                 .  |   .                 |
        13       -0.07294    |                 .  *|   .                 |
        14        0.07859    |                 .  |** .                 |
        15        0.01143    |                 .  |   .                 |
        16        0.01091    |                 .  |   .                 |
        17        0.09477    |                 .  |** .                 |
        18        0.07647    |                 .  |** .                 |
        19        0.09736    |                 .  |** .                 |
        20       -0.06456    |                 .  *|   .                 |
        21       -0.03364    |                 .  *|   .                 |
        22        0.05364    |                 .  |*  .                 |
```



```
                               The ARIMA Procedure

                              Inverse Autocorrelations

       Lag    Correlation    -1 9 8 7 6 5 4 3 2 1 0 1 2 3 4 5 6 7 8 9 1

        23        0.10670    |                 .  |** .                 |
```

```
  24      0.00399   |                .  |  .                  |
```

Partial Autocorrelations

```
Lag   Correlation   -1 9 8 7 6 5 4 3 2 1 0 1 2 3 4 5 6 7 8 9 1

  1     -0.07614    |                . **|   .                 |
  2      0.12991    |                .   |***.                 |
  3      0.02901    |                .   |*  .                 |
  4     -0.01675    |                .   |   .                 |
  5     -0.09064    |                . **|   .                 |
  6     -0.06645    |                .  *|   .                 |
  7      0.12306    |                .   |** .                 |
  8     -0.11123    |                . **|   .                 |
  9      0.00556    |                .   |   .                 |
 10     -0.07297    |                .  *|   .                 |
 11      0.02734    |                .   |*  .                 |
 12     -0.02003    |                .   |   .                 |
 13      0.13331    |                .   |***.                 |
 14     -0.07018    |                .  *|   .                 |
 15     -0.03271    |                .  *|   .                 |
 16     -0.05081    |                .  *|   .                 |
 17     -0.10057    |                . **|   .                 |
 18     -0.03101    |                .  *|   .                 |
 19     -0.10836    |                . **/   .                 |
 20      0.04703    |                .   |*  .                 |
 21      0.01506    |                .   |   .                 |
 22     -0.04876    |                .  *|   .                 |
 23     -0.11979    |                . **|   .                 |
 24     -0.00450    |                .   |   .                 |
```


The ARIMA Procedure

Model for variable KWH

```
Estimated Intercept         17537.7
Period(s) of Differencing        12
```

Autoregressive Factors

Factor 1: 1 - 0.41381 B**(1) - 0.05316 B**(3) + 0.1791 B**(4)

Moving Average Factors

Factor 1: 1 - 0.8281 B**(12)

Input Number 1

Input Variable	or1
Period(s) of Differencing	12
Overall Regression Factor	64424.59

Forecasts for variable KWH

Obs	Forecast	Std Error	95% Confidence Limits	
137	809181.3	22659.07	764770.3	853592.2
138	750587.6	24522.50	702524.3	798650.8
139	792668.5	24827.57	744007.3	841329.6
140	847902.7	24986.11	798930.9	896874.6
141	914080.5	25100.81	864883.8	963277.2
142	1023010.9	25221.55	973577.6	1072444.2
143	1082174.5	25270.09	1032646.1	1131703.0
144	1163193.7	25302.42	1113601.9	1212785.6
145	1151958.2	25303.47	1102364.3	1201552.1
146	993931.6	25304.83	944335.0	1043528.1

The ARIMA Procedure

Forecasts for variable KWH

Obs	Forecast	Std Error	95% Confidence Limits

147	991769.6	25306.07	942169.0	1041370.1
148	888331.9	25309.29	838726.7	937937.2
149	827139.8	25638.45	776889.3	877390.2
150	770583.5	25692.43	720227.3	820939.8
151	811952.4	25700.65	761580.0	862324.7
152	867849.7	25704.15	817470.5	918228.9
153	932670.5	25708.44	882282.9	983058.1
154	1040636.6	25712.51	990241.0	1091032.2
155	1099564.0	25714.07	1049165.3	1149962.6

The ARIMA Procedure

Maximum Likelihood Estimation

Parameter	Estimate	Standard Error	t Value	Approx Pr > |t|	Lag	Variable	Shift
MU	80306.6	58844.2	1.36	0.1723	0	KWH	0
AR1,1	-0.30827	0.08672	-3.55	0.0004	1	KWH	0
AR1,2	-0.31377	0.10135	-3.10	0.0020	12	KWH	0
NUM1	3221.7	1415.4	2.28	0.0228	0	bcdd65	0
NUM2	3235.2	840.60253	3.85	0.0001	0	bhdd55	0
NUM3	14998708	616407.1	24.33	<.0001	0	muni1	0
NUM4	13603874	650693.7	20.91	<.0001	0	muni2	0
NUM5	3822374.2	225030.0	16.99	<.0001	0	muni3	0

Constant Estimate	130259.8
Variance Estimate	9.259E11
Std Error Estimate	962248.9
AIC	3777.844
SBC	3800.407
Number of Residuals	124

Correlations of Parameter Estimates

Variable	KWH	KWH	KWH	bcdd65	bhdd55	muni1	muni2	muni3
Parameter	MU	AR1,1	AR1,2	NUM1	NUM2	NUM3	NUM4	NUM5

KWH	MU	1.000	-0.007	0.025	0.083	0.004	-0.000	-0.008	-0.385
KWH	AR1,1	-0.007	1.000	-0.195	-0.147	-0.136	-0.147	0.005	0.003
KWH	AR1,2	0.025	-0.195	1.000	-0.029	-0.042	-0.027	-0.353	-0.045
bcdd65	NUM1	0.083	-0.147	-0.029	1.000	0.031	0.025	0.024	0.009
bhdd55	NUM2	0.004	-0.136	-0.042	0.031	1.000	0.089	0.026	-0.022
muni1	NUM3	-0.000	-0.147	-0.027	0.025	0.089	1.000	0.020	0.000
muni2	NUM4	-0.008	0.005	-0.353	0.024	0.026	0.020	1.000	0.016
muni3	NUM5	-0.385	0.003	-0.045	0.009	-0.022	0.000	0.016	1.000

The ARIMA Procedure

Autocorrelation Check of Residuals

To Lag	Chi-Square	DF	Pr > ChiSq	Autocorrelations					
6	10.11	4	0.0386	-0.061	-0.014	0.191	-0.179	-0.002	0.074
12	12.15	10	0.2750	0.034	-0.039	-0.028	-0.002	0.075	-0.076
18	14.52	16	0.5601	-0.043	0.042	-0.034	0.098	0.006	-0.046
24	26.81	22	0.2185	0.102	-0.161	0.065	0.066	-0.136	-0.130

Autocorrelation Plot of Residuals

```
Lag    Covariance    Correlation    -1 9 8 7 6 5 4 3 2 1 0 1 2 3 4 5 6 7 8 9 1      Std Error

  0    9.25923E11       1.00000     |                    ....................|              0
  1    -5.6184E10       -.06068     |                .  *|  .                |       0.089803
  2    -1.2761E10       -.01378     |                .   |  .                |       0.090133
  3    1.76739E11       0.19088     |                .   |****               |       0.090150
  4    -1.6609E11       -.17938     |                ****|  .                |       0.093352
  5    -2.25765E9       -.00244     |                .   |  .                |       0.096092
  6    6.84161E10       0.07389     |                .   |* .                |       0.096092
  7    3.19238E10       0.03448     |                .   |* .                |       0.096549
  8    -3.6286E10       -.03919     |                .  *|  .                |       0.096649
  9    -2.5608E10       -.02766     |                .  *|  .                |       0.096777
 10    -2.14118E9       -.00231     |                .   |  .                |       0.096840
 11    6.92904E10       0.07483     |                .   |* .                |       0.096841
```

```
 12    -7.0024E10     -.07563   |                 . **|   .                |    0.097306
 13    -3.9436E10     -.04259   |                 .  *|   .                |    0.097779
 14    3.84697E10     0.04155   |                 .   |*  .                |    0.097928
 15    -3.1256E10     -.03376   |                 .  *|   .                |    0.098070
 16    9.06338E10     0.09788   |                 .   |** .                |    0.098164
 17    5938922444     0.00641   |                 .   |   .                |    0.098948
 18    -4.2559E10     -.04596   |                 .  *|   .                |    0.098951
 19    9.48905E10     0.10248   |                 .   |** .                |    0.099124
 20     -1.495E11     -.16146   |                 .***|   .                |    0.099974
 21    6.01319E10     0.06494   |                 .   |*  .                |    0.102055
```



```
                              The ARIMA Procedure

                        Autocorrelation Plot of Residuals

Lag    Covariance    Correlation    -1 9 8 7 6 5 4 3 2 1 0 1 2 3 4 5 6 7 8 9 1      Std Error

 22    6.15602E10      0.06649      |                 .   |*  .                |    0.102388
 23    -1.2599E11      -.13607      |                 .***|   .                |    0.102736
 24    -1.2017E11      -.12978      |                 .***|   .                |    0.104179

                         "." marks two standard errors


                            Inverse Autocorrelations

       Lag    Correlation    -1 9 8 7 6 5 4 3 2 1 0 1 2 3 4 5 6 7 8 9 1

         1     -0.04797      |                 .  *|   .                |
         2     -0.07087      |                 .  *|   .                |
         3     -0.20932      |                 ****|   .                |
         4      0.29559      |                 .   |******              |
         5     -0.01268      |                 .   |   .                |
         6     -0.07283      |                 .  *|   .                |
         7     -0.16437      |                 .***|   .                |
         8      0.15492      |                 .   |***.                |
         9      0.00767      |                 .   |   .                |
        10     -0.00611      |                 .   |   .                |
        11     -0.11667      |                 . **|   .                |
```

```
  12        0.13171   |                 .   |***.                 |
  13        0.01476   |                 .   |   .                 |
  14        0.01151   |                 .   |   .                 |
  15        0.07032   |                 .  *|   .                 |
  16        0.03059   |                 .   |*  .                 |
  17        0.07541   |                 . **|   .                 |
  18        0.03760   |                 .   |*  .                 |
  19       -0.06629   |                 .  *|   .                 |
  20        0.15075   |                 .   |***.                 |
  21        0.10547   |                 . **|   .                 |
  22        0.00127   |                 .   |   .                 |
```

Wholesale Municipals   12:01 Tuesday, September 3, 2002 59

The ARIMA Procedure

Inverse Autocorrelations

```
 Lag    Correlation    -1 9 8 7 6 5 4 3 2 1 0 1 2 3 4 5 6 7 8 9 1

  23        0.03497   |                 .   |*  .                 |
  24        0.16448   |                 .   |***.                 |
```

Partial Autocorrelations

```
 Lag    Correlation    -1 9 8 7 6 5 4 3 2 1 0 1 2 3 4 5 6 7 8 9 1

   1       -0.06068   |                 .  *|   .                 |
   2       -0.01753   |                 .   |   .                 |
   3        0.18972   |                 .   |****                 |
   4       -0.16331   |                 .***|   .                 |
   5       -0.01444   |                 .   |   .                 |
   6        0.03806   |                 .   |*  .                 |
   7        0.10832   |                 .   |** .                 |
   8       -0.06595   |                 .  *|   .                 |
   9       -0.05886   |                 .  *|   .                 |
  10       -0.01131   |                 .   |   .                 |
  11        0.13255   |                 .   |* **.                |
  12       -0.08452   |                 .  *|   .                 |
  13       -0.08218   |                 .  *|   .                 |
```

```
14       0.00406   |            .   |   .          |
15       0.05147   |            .   |*  .          |
16       0.10374   |            .   |** .          |
17       0.05040   |            .  *|   .          |
18       0.05194   |            .  *|   .          |
19       0.12068   |            .   |** .          |
20      -0.11607   |            . **|   .          |
21       0.04790   |            .   |*  .          |
22      -0.01291   |            .   |   .          |
23      -0.04201   |            .  *|   .          |
24       0.21046   |            ****|   .          |
```

```
                    Wholesale Municipals            12:01 Tuesday, September 3, 2002  60

                    The ARIMA Procedure

                  Model for variable KWH

              Estimated Intercept         30306.58
              Period(s) of Differencing         12


                  Autoregressive Factors

Factor 1   1 + 0.30827 B**(1) + 0.31377 B**(12)


                      Input Number 1

              Input Variable                bcdd55
              Period(s) of Differencing         12
              Overall Regression Factor   3221.677


                      Input Number 2

              Input Variable                bhdd55
              Period(s) of Differencing         12
              Overall Regression Factor   3235.208
```

Input Number 3

Input Variable	muni1
Period(s) of Differencing	12
Overall Regression Factor	14998708

Input Number 4

Input Variable	muni2
Period(s) of Differencing	12
Overall Regression Factor	13603874

The ARIMA Procedure

Input Number 5

Input Variable	muni3
Period(s) of Differencing	12
Overall Regression Factor	3822374

Forecasts for variable KWH

Obs	Forecast	Std Error	95% Confidence Limits	
137	4961466.3	962249	3075493.2	6847439.4
138	6773728.8	1006932	4800178.9	8747278.7
139	7172658.2	1011075	5190987.4	9154329.0
140	7496849.0	1011468	5514408.2	9479289.8
141	5899904.6	1011505	3917390.6	7882418.5
142	5724488.6	1011509	3741967.7	7707009.5
143	7177788.1	1011509	5195266.5	9160309.6
144	6642587.7	1011509	4660066.1	8625109.4
145	10560630.9	1011509	8578109.3	12543152.6
146	8294437.9	1011509	6311916.2	10276959.5
147	7113284.6	1011509	5130763.0	9095806.3
148	7182518.2	1011509	5199996.6	9165039.9
149	5518826.8	1207967	3151254.4	7886399.2

150	6610814.6	1213009	4233359.7	8988269.4
151	7403966.4	1213021	5026488.3	9781444.5
152	7528627.4	1213043	5151107.6	9906147.3
153	5938006.9	1213053	3560467.3	8815546.5
154	5855746.6	1213055	3478202.5	8233290.7
155	7210213.7	1213055	4832668.8	9587758.6

Long-term Residential and Commercial Models

KENTUCKY POWER COMPANY
RESIDENTIAL CUSTOMERS
ENDOGENOUS VARIABLES

The MEANS Procedure

Variable	Label	Mean
year	year	1999.00
CR_KPC	RESIDENTIAL CUSTOMERS	129.3961728

KENTUCKY POWER COMPANY
RESIDENTIAL CUSTOMERS
ENDOGENOUS VARIABLES

Obs	year	CR_KPC
1	1975	106.399
2	1976	110.549
3	1977	113.651
4	1978	116.439
5	1979	118.910
6	1980	121.094
7	1981	122.698
8	1982	124.206
9	1983	125.325
10	1984	126.300
11	1985	127.027
12	1986	127.676
13	1987	128.135
14	1988	128.973
15	1989	130.028
16	1990	131.085
17	1991	132.295
18	1992	133.840
19	1993	135.697
20	1994	137.435
21	1995	139.392
22	1996	140.844
23	1997	142.197

24	1998	142.598
25	1999	143.174
26	2000	143.652
27	2001	144.079
28	2002	
29	2003	
30	2004	
31	2005	
32	2006	
33	2007	
34	2008	
35	2009	

KENTUCKY POWER COMPANY
RESIDENTIAL CUSTOMERS
ENDOGENOUS VARIABLES

Obs	year	CR_KPC
36	2010	
37	2011	
38	2012	
39	2013	
40	2014	
41	2015	
42	2016	
43	2017	
44	2018	
45	2019	
46	2020	
47	2021	
48	2022	
49	2023	

KENTUCKY POWER COMPANY
RESIDENTIAL CUSTOMERS
EXOGENOUS VARIABLES

The MEANS Procedure

Variable	Label	Mean

year	year	1999.00
L_KPC	SERVICE AREA EMPLOYMENT	132.8100000
D7576	BINARY VARIABLE, 1975 AND 1976	0.0408163
D77	BINARY VARIABLE, 1977	0.0204082
D98ON	BINARY VARIABLE, 1998 ON	0.5306122
D01ON	BINARY VARIABLE, 2001 ON	3.4693878

KENTUCKY POWER COMPANY
RESIDENTIAL CUSTOMERS
EXOGENOUS VARIABLES

Obs	year	L_KPC	D7576	D77	D98ON	D01ON
1	1975	95.261	1	0	0	0
2	1976	98.510	1	0	0	0
3	1977	103.072	0	1	0	0
4	1978	107.705	0	0	0	0
5	1979	113.643	0	0	0	0
6	1980	111.217	0	0	0	0
7	1981	111.092	0	0	0	0
8	1982	108.646	0	0	0	0
9	1983	99.789	3	0	0	0
10	1984	104.823	0	0	0	0
11	1985	106.334	0	0	0	0
12	1986	105.546	0	0	0	0
13	1987	107.886	0	0	0	0
14	1988	110.905	0	0	0	0
15	1989	113.335	0	0	0	0
16	1990	117.613	0	0	0	0
17	1991	116.774	0	0	0	0
18	1992	118.813	0	0	0	0
19	1993	118.786	0	0	0	0
20	1994	121.273	0	0	0	0
21	1995	122.499	0	0	0	0
22	1996	122.225	0	0	0	0
23	1997	123.711	0	0	0	0
24	1998	125.778	0	0	1	0
25	1999	127.284	0	0	1	0
26	2000	127.987	0	0	1	0
27	2001	130.784	0	0	1	1

28	2002	134.450	0	0	1	1
29	2003	136.966	0	0	1	1
30	2004	139.962	0	0	1	1
31	2005	141.744	0	0	1	1
32	2006	143.612	0	0	1	1
33	2007	145.626	0	0	1	1
34	2008	147.533	0	0	1	1
35	2009	149.327	0	0	1	1

KENTUCKY POWER COMPANY
RESIDENTIAL CUSTOMERS
EXOGENOUS VARIABLES

Obs	year	L_KPC	D7576	D77	D98ON	DO1ON
36	2010	151.142	0	0	1	1
37	2011	153.018	0	0	1	1
38	2012	155.215	0	0	1	1
39	2013	157.350	0	0	1	1
40	2014	159.390	0	0	1	1
41	2015	161.401	0	0	1	1
42	2016	163.369	0	0	1	1
43	2017	165.320	0	0	1	1
44	2018	167.241	0	0	1	1
45	2019	169.136	0	0	1	1
46	2020	170.979	0	0	1	1
47	2021	172.778	0	0	1	1
48	2022	174.569	0	0	1	1
49	2023	176.271	0	0	1	1

KENTUCKY POWER COMPANY
RESIDENTIAL CUSTOMERS
MODEL ESTIMATION

The SYSLIN Procedure
Ordinary Least Squares Estimation

Model	CR_KPC
Dependent Variable	CR_KPC
Label	**RESIDENTIAL CUSTOMERS**

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	6	2898.071	483.0119	3892.67	<.0001
Error	20	2.481647	0.124082		
Corrected Total	26	2900.553			

Root MSE	0.35225	R-Square	0.99914
Dependent Mean	129.39617	Adj R-Sq	0.99889
Coeff Var	0.27223		

Parameter Estimates

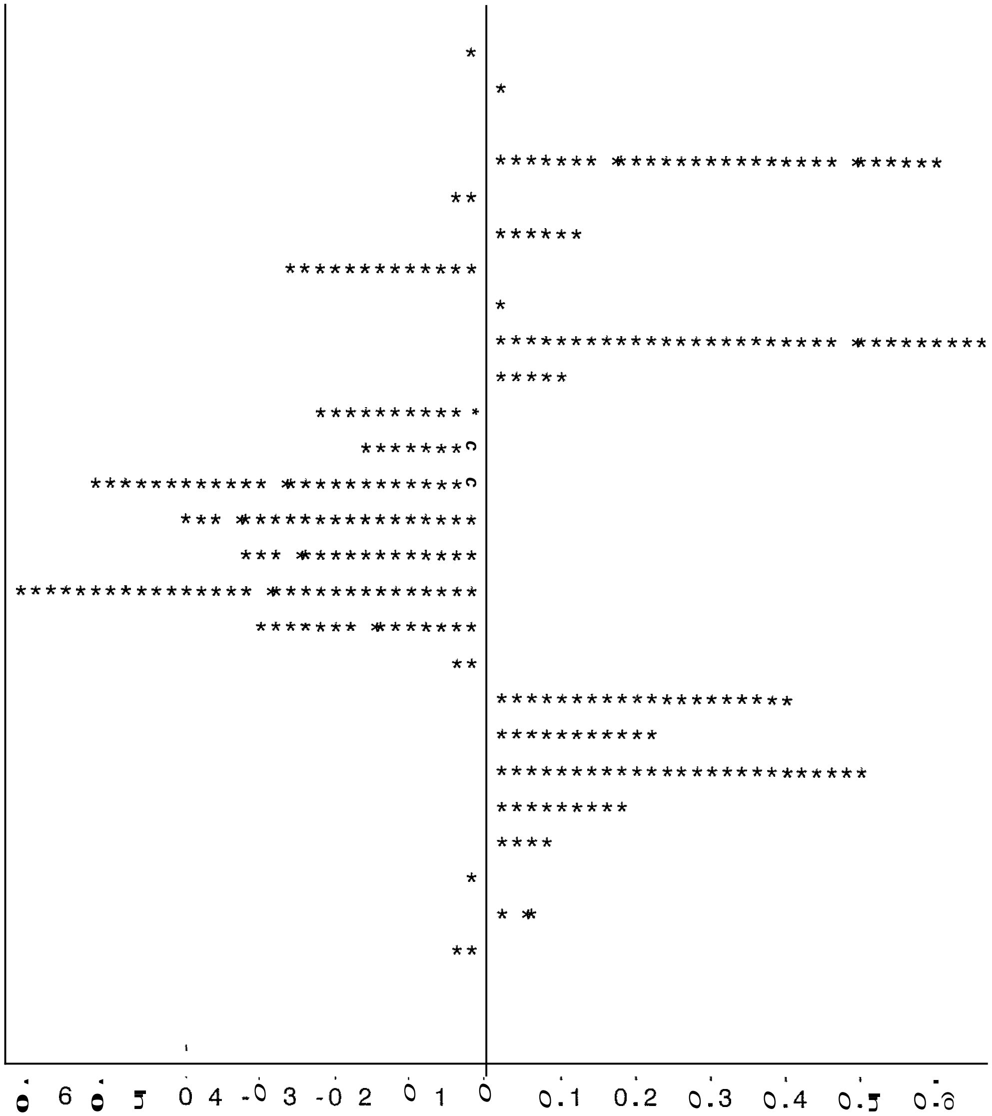
Variable	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|	Variable Label
Intercept	1	-37.3367	7.604549	-4.91	<.0001	Intercept
CR_KPC1	1	0.911852	0.015461	58.98	<.0001	RESIDENTIAL CUSTOMERS, LAG 1-YEAR
LL	1	10.58887	1.878144	5.64	<.0001	SERVICE AREA EMPLOYMENT, LOG
D7576	1	2.240645	0.368737	6.08	<.0001	BINARY VARIABLE, 1975 AND 1976
D77	1	1.099607	0.408847	2.69	0.0141	BINARY VARIABLE, 1977
D98ON	1	-0.89915	0.276818	-3.25	0.0040	BINARY VARIABLE, 1998 ON
D01ON	1	-0.27995	0.409269	-0.68	0.5018	BINARY VARIABLE, 2001 ON

KENTUCKY POWER COMPANY
RESIDENTIAL CUSTOMERS
MODEL ESTIMATION

The SYSLIN Procedure
Ordinary Least Squares Estimation

Durbin-Watson	1.087241
Number of Observations	27
First-Order Autocorrelation	0.4563

KENTUCKY POWER COMPANY
RESIDENTIAL CUSTOMERS
MODEL RESIDUALS



year	Residual Values Sum
1975	-0.019798
1976	0.019798
1977	0.000000
1978	0.592489
1979	-0.045833
1980	0.112518
1981	-0.262353
1982	0.018556
1983	0.662928
1984	0.096931
1985	-0.217294
1986	-0.152879
1987	-0.516835
1988	-0.390072
1989	-0.328458
1990	-0.626024
1991	-0.304544
1992	-0.045727
1993	0.405368
1994	0.229444
1995	0.496652
1996	0.186775
1997	0.088357
1998	-0.021331
1999	0.063197
2000	0.0418[illegible]
2001	0.000000

Residual Values
KENTUCKY POWER COMPANY
RESIDENTIAL CUSTOMERS
MODEL SIMULATION

The SIMLIN Procedure

Inverse Coefficient Matrix for Endogenous Variables

Variable	CR-KPC
CR-KPC	1.0000

Reduced Form for Lagged Endogenous Variables

Variable	CR_KPC1
CR-KPC	0.9119

Reduced Form for Exogenous Variables

Variable	LL	D7576	D77	D98ON	DO1ON	Intercept
CR-KPC	10.5889	2.2406	1.0996	-0.8992	-0.2800	-37.3367

KENTUCKY POWER COMPANY
RESIDENTIAL CUSTOMERS
MODEL SIMULATION

The SIMLIN Procedure

Fit Statistics

Variable	N	Mean Error	Mean Pct Error	Mean Abs Error	Mean Abs Pct Error	RMS Error	RMS Pct Error	Label
CR-KPC	27	-0.0544	-0.0327	0.4983	0.38414	0.6645	0.5104	RESIDENTIAL CUSTOMERS

KENTUCKY POWER COMPANY
RESIDENTIAL CUSTOMERS
ACTUAL AND FORECAST

year	RESIDENTIAL CUSTOMERS	GROWTH RATE

1975	106.399	
1976	110.549	3.9
1977	113.651	2.8
1978	116.439	2.5
1979	118.910	2.1
1980	121.094	1.8
1981	122.698	1.3
1982	124.206	1.2
1983	125.325	0.9
1984	126.300	0.8
1985	127.027	0.6
1986	127.676	0.5
1987	128.135	0.4
1988	128.973	0.7
1989	130.028	0.8
1990	131.085	0.8
1991	132.295	0.9
1992	133.840	1.2
1993	135.697	1.4
1994	137.435	1.3
1995	139.392	1.4
1996	140.844	1.0
1997	142.197	1.0
1998	142.598	0.3
1999	143.174	0.4
2000	143.652	0.3
2001	144.079	0.3
2002	144.632	0.4
2003	145.461	0.6
2004	146.447	0.7
2005	147.480	0.7
2006	148.560	0.7
2007	149.693	0.8

KENTUCKY POWER COMPANY
RESIDENTIAL CUSTOMERS
ACTUAL AND FORECAST

RESIDENTIAL GROWTH

year	CUSTOMERS	RATE
2008	150.863	0.8
2009	152.059	0.8
2010	153.277	0.8
2011	154.518	0.8
2012	155.800	0.8
2013	157.115	0.8
2014	158.450	0.8
2015	159.800	0.9
2016	161.159	0.9
2017	162.524	0.8
2018	163.891	0.8
2019	165.257	0.8
2020	166.617	0.8
2021	167.969	0.8
2022	169.310	0.8
2023	170.636	0.8

KENTUCKY POWER COMPANY
RESIDENTIAL USAGE/ENERGY SALES
ENDOGENOUS VARIABLES

The MEANS Procedure

Variable	Label	Mean
year	year	1999.00
ER_KPC	ENERGY SALES, RESIDENTIAL	1749.41
USE	RES. ELEC. ENERGY USAGE PER CUSTOMER	13.3800094

KENTUCKY POWER COMPANY
RESIDENTIAL USAGE/ENERGY SALES
ENDOGENOUS VARIABLES

Obs	year	ER_KPC	USE
1	1975	972.23	9.1376
2	1976	1117.90	10.1123
3	1977	1250.72	11.0049
4	1978	1379.11	11.8441

5	1979	1398.69	11.7626
6	1980	1468.72	12.1288
7	1981	1534.82	12.5089
8	1982	1511.41	12.1686
9	1983	1613.65	12.8757
10	1984	1581.79	12.5241
11	1985	1573.25	12.3852
12	1986	1609.45	12.6058
13	1987	1681.27	13.1211
14	1988	1777.39	13.7811
15	1989	1735.86	13.3499
16	1990	1717.96	13.1357
17	1991	1897.05	14.3396
18	1992	1886.02	14.0917
19	1993	1971.56	14.5291
20	1994	2024.84	14.7331
21	1995	2191.98	15.7253
22	1996	2190.61	15.5535
23	1997	2196.75	15.4486
24	1998	2156.13	15.1203
25	1999	2158.36	15.0751
26	2000	2324.01	16.1780
27	2001	2312.43	16.0497
28	2002		
29	2003		
30	2004		
31	2005		
32	2006		
33	2007		
34	2008		
35	2009		

KENTUCKY POWER COMPANY
RESIDENTIAL USAGE/ENERGY SALES
ENDOGENOUS VARIABLES

Obs	year	ER_KPC	USE
36	2010		
37	2011		
38	2012		

39	2013
40	2014
41	2015
42	2016
43	2017
44	2018
45	2019
46	2020
47	2021
48	2022
49	2023

KENTUCKY POWER COMPANY
RESIDENTIAL USAGE/ENERGY SALES
EXOGENOUS VARIABLES

The MEANS Procedure

Variable	Label	Mean
YEAR	year	1999.00
L_KPC	SERVICE AREA EMPLOYMENT	132.8100000
HDD-HUNT	HUNTINGTON, WV HEATING DEGREE DAYS	4523.04
CDD_HUNT	HUNTINGTON, WV COOLING DEGREE DAYS	1170.54
D80	BINARY VARIABLE, 1980	0.0204082
DO1ON	BINARY VARIABLE, 2001 ON	0.4693878
GPRNDX	REAL KY RES. GAS PRICE INDEX, 2001=1.00	0.7469388
PRNDX	REAL RES. ELEC. PRICE INDEX, 2001=1.00	1,2171429

KENTUCKY POWER COMPANY
RESIDENTIAL USAGE/ENERGY SALES
EXOGENOUS VARIABLES

Obs	YEAR	L_KPC	HDD-HUNT	CDD_HUNT	D80	D01ON	GPRNDX	PRNDX
1	1975	95.261	4249.00	1274.00	0	0	0.42	1.72
2	1976	98.510	4736.00	867.00	0	0	0.43	1.60
3	1977	103.072	4754.00	1373.00	0	0	0.54	1.76
4	1978	107.705	5150.00	1308.00	0	0	0.54	1.71
5	1979	113.643	4753.00	1004.00	0	0	0.59	1.70
6	1980	111.217	5021.00	1310.00	1	0	0.68	1.56

7	1981	111.092	4847.00	1138.00	0	0	0.70	1.57
8	1982	108.646	4502.00	822.00	0	0	0.85	1.61
9	1983	99.789	4683.00	1374.00	0	0	0.98	1.67
10	1984	104.823	4452.00	1193.00	0	0	0.92	1.64
11	1985	106.334	4502.00	1047.00	0	0	0.90	1.84
12	1986	105.546	4258.00	1360.00	0	0	0.82	1.83
13	1987	107.886	4409.00	1366.00	0	0	0.73	1.66
14	1988	110.905	4852.00	1217.00	0	0	0.70	1.55
15	1989	113.335	4828.00	1080.00	0	0	0.69	1.53
16	1990	117.613	3627.00	1165.00	0	0	0.69	1.51
17	1991	116.774	3975.00	1670.00	0	0	0.66	1.40
18	1992	118.813	4401.00	942.00	0	0	0.66	1.36
19	1993	118.786	4587.00	1294.00	0	0	0.67	1.27
20	1994	121.273	4362.00	1100.00	0	0	0.68	1.25
21	1995	122.499	4733.00	1264.00	0	0	0.61	1.20
22	1996	122.225	4878.00	1087.00	0	0	0.65	1.15
23	1997	123.711	4708.00	839.00	0	0	0.73	1.12
24	1998	125.778	3869.00	1267.00	0	0	0.68	1.11
25	1999	127.284	4197.00	1244.00	0	0	0.63	1.11
26	2000	127.987	4603.00	978.00	0	0	0.79	1.05
27	2001	130.784	4264.00	1120.00	0	1	1.00	1.00
28	2002	134.450	4519.50	1166.07	0	I	0.75	0.98
29	2003	136.966	4519.50	1166.07	0	1	0.78	0.96
30	2004	139.962	4519.50	1166.07	0	1	0.79	0.93
31	2005	141.744	4519.50	1166.07	0	1	0.80	0.91
32	2006	143.612	4519.50	1166.07	0	1	0.79	0.91
33	2007	145.626	4519.50	1166.07	0	1	0.79	0.91
34	2008	147.533	4519.50	1166.07	0	1	0.79	0.91
35	2009	149.327	4519.50	1166.07	0	1	0.78	0.91

KENTUCKY POWER COMPANY

RESIDENTIAL USAGE/ENERGY SALES

EXOGENOUS VARIABLES

Obs	YEAR	L_KPC	HDD_HUNT	CDD_HUNT	**D80**	D01ON	GPRNDX	PRNDX
36	2010	151.142	4519.50	1166.07	0	1	0.78	0.91
37	2011	153.018	4519.50	1166.07	0	1	0.78	0.91
38	2012	155.215	4519.50	1166.07	0	1	0.79	0.91
39	2013	157.350	4519.50	1166.07	0	1	0.79	0.91
40	2014	159.390	4519.50	1166.07	0	1	0.79	0.91

41	2015	161.401	4519.50	1166.07	0	1	0.80	0.91
42	2016	163.369	4519.50	1166.07	0	1	0.80	0.91
43	2017	165.320	4519.50	1166.07	0	1	0.81	0.91
44	2018	167.241	4519.50	1166.07	0	1	0.81	0.91
45	2019	169.136	4519.50	1166.07	0	1	0.83	0.91
46	2020	170.979	4519.50	1166.07	0	1	0.84	0.91
47	2021	172.778	4519.50	1166.07	0	1	0.85	0.91
48	2022	174.569	4519.50	1166.07	0	1	0.86	0.91
49	2023	176.271	4519.50	1166.07	0	1	0.86	0.91

KENTUCKY POWER COMPANY
RESIDENTIAL USAGE/ENERGY SALES
MODEL ESTIMATION

The SYSLIN Procedure
Ordinary Least Squares Estimation

Model	USE
Dependent Variable	USE
Label	RES. ELEC. ENERGY USAGE PER CUSTOMER

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	6	82.92287	13.82048	92.69	<.0001
Error	20	2.982090	0.149104		
Corrected Total	26	85.90496			

Root MSE	0.38614	R-Square	0.96529
Dependent Mean	13.38001	Adj R-Sq	0.95487
Coeff Var	2.88595		

Parameter Estimates

Variable	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|	Variable Label

Intercept	1	-58.0668	6.478947	-8.96	<.0001	Intercept
LPRGPR5	1	-2.84343	0.370748	-7.67	<.0001	RES. ELEC./RES. GAS PRICE RATIO, LOG
LL	1	13.95762	1.300099	10.74	<.0001	SERVICE AREA EMPLOYMENT, LOG
D80	1	-0.91939	0.425251	-2.16	0.0429	BINARY VARIABLE, 1980
DO1ON	1	-0.44712	0.421839	-1.06	0.3018	BINARY VARIABLE, 2001 ON
HDD_HUNT	1	0.000972	0.000246	3.95	0.0008	HUNTINGTON, WV HEATING DEGREE DAYS
CDD_HUNT	1	0.001208	0.000421	2.87	0.0095	HUNTINGTON, WV COOLING DEGREE DAYS

KENTUCKY POWER COMPANY
RESIDENTIAL USAGE/ENERGY SALES
MODEL ESTIMATION

The SYSLIN Procedure
Ordinary Least Squares Estimation

Durbin-Watson	1.465834
Number of Observations	27
First-Order Autocorrelation	0.261948

KENTUCKY POWER COMPANY
RESIDENTIAL USAGE/ENERGY SALES
MODEL RESIDUALS

year			Residual Values Sum
1975		*********	0.175003
1976		****************************	0.560565
1977	*		-0.015261
1978	*************		-0.268781
1979	******************************		-0.628987
1980			-0.000000
1981	**********************		-0.430200
1982	***		-0.064321
1983		*******************************	0.627851
1984	***********		-0.220447
1985	************************		-0.489717
1986	***************		-0.294878
1987	*******		-0.149329
1988		*	0.025597
1989	********************		-0.395256

1990	**	-0.045151
1991	****************	0.319888
1992		0.244234
1993		-0.004376
1994		0.262581
1995		0.497350
1996		0.325560
1997		0.341519
1998		-0.009470
1999		-0.543839
2000		0.179864
2001		-0.000000

Residual Values

KENTUCKY POWER COMPANY
RESIDENTIAL USAGE/ENERGY SALES
ACTUAL AND FORECAST

year	RESIDENTIAL USAGE	RESIDENTIAL ENERGY SALES	GROWTH RATE
1975	9.1376	972.23	
1976	10.1123	1117.90	15.0
1977	11.0049	1250.72	11.9
1978	11.8441	1379.11	10.3
1979	11.7626	1398.69	1.4
1980	12.1288	1468.72	5.0
1981	12.5089	1534.82	4.5
1982	12.1686	1511.41	-1.5
1983	12.8757	1613.65	6.8
1984	12.5241	1581.79	-2.0
1985	12.3852	1573.25	-0.5
1986	12.6058	1609.45	2.3
1987	13.1211	1681.27	4.5
1988	13.7811	1777.39	5.7
1989	13.3499	1735.86	-2.3

1990	13.1057	1717.96	-1.0
1991	14.3396	1897.05	10.4
1992	14.0917	1886.02	-0.6
1993	14.5291	1971.56	4.5
1994	14.7331	2024.84	2.7
1995	15.7253	2191.98	8.3
1996	15.5535	2190.61	-0.1
1997	15.4486	2196.75	0.3
1998	15.1203	2156.13	-1.8
1999	15.0751	2158.36	0.1
2000	16.1780	2324.01	7.7
2001	16.0497	2312.43	-0.5
2002	16.8296	2434.10	5.3
2003	17.2436	2508.28	3.0
2004	17.7579	2600.59	3.7
2005	18.0202	2657.61	2.2
2006	18.1089	2690.26	1.2
2007	18.3723	2750.20	2.2

KENTUCKY POWER COMPANY
RESIDENTIAL USAGE/ENERGY SALES
ACTUAL AND FORECAST

year	RESIDENTIAL USAGE	RESIDENTIAL ENERGY SALES	GROWTH RATE
2008	18.5897	2804.51	2.0
2009	18.7661	2853.54	1.7
2010	18.9228	2900.42	?.6
20'1	19.0883	2949.48	1.7
2012	19.2873	3004.97	1.9
2013	19.4806	3060.69	1.9
2014	19.6671	3116.24	1.8
2015	19.8553	3172.87	1.8
2016	20.0376	3229.24	1.8
2017	20.2177	3285.87	1.8
2018	20.3959	3342.71	1.7
2019	20.5765	3400.41	1.7
2020	20.7560	3458.31	1.7
2021	20.9325	3516.01	1.7

2022	21.1091	3573.98	1.6
2023	21.2780	3630.79	1.6

KENTUCKY POWER COMPANY
COMMERCIAL ENERGY SALES
ENDOGENOUS VARIABLES

The MEANS Procedure

Variable	Label	Mean
year	year	1999.00
EC_KPC	ENERGY SALES, COMMERCIAL	869.341 2389

KENTUCKY POWER COMPANY
COMMERCIAL ENERGY SALES
ENDOGENOUS VARIABLES

Obs	year	EC_KPC
1	1975	420.20
2	1976	461 .77
3	1977	513.49
4	1978	554.89
5	1979	581.37
6	1980	630.95
7	1981	669.18
8	1982	685.51
9	1983	700.15
10	1984	714.59
11	1985	761.99
12	1986	786.15
13	1987	831.77
14	1988	869.40
15	1989	885.68
16	1990	919.62
17	1991	988.98
18	1992	991.36
19	1993	1034.39
20	1994	1072.37
21	1995	1134.51

22	1996	1150.45
23	1997	1165.68
24	1998	1194.52
25	1999	1230.93
26	2000	1243.52
27	2001	1278.78
28	2002	
29	2003	
30	2004	
31	2005	
32	2006	
33	2007	
34	2008	
35	2009	

KENTUCKY POWER COMPANY
COMMERCIAL ENERGY SALES
ENDOGENOUS VARIABLES

Obs	year	EC_KPC
36	2010	
37	2011	
38	2012	
39	2013	
40	2014	
41	2015	
42	2016	
43	2017	
44	2018	
45	2019	
46	2020	
47	2021	
48	2022	
49	2023	

KENTUCKY POWER COMPANY
COMMERCIAL ENERGY SALES
EXOGENOUS VARIABLE

The MEANS Procedure

Variable	Label	Mean
YEAR	year	1999.00
CR_KPC	RESIDENTIAL CUSTOMERS	141.7390359
D7576	BINARY VARIABLE, 1975 AND 1976	0.0408163
D79	BINARY VARIABLE, 1979	0.0204082
DOOON	BINARY VARIABLE, 2000 ON	0.4897959
LCOM	SERVICE AREA COMMERCIAL EMPLOYMENT	85.8160408
PCNDX	REAL COM. ELEC. PRICE INDEX, 2001=1.00	1.2528571
GPCNDX	REAL KY COM. GAS PRICE INDEX, 2001=1.00	1.4171429

KENTUCKY POWER COMPANY

COMMERCIAL ENERGY SALES

EXOGENOUS VARIABLE

Obs	YEAR	CR_KPC	D7576	D79	DOOON	LCOM	PCNDX	GPCNDX
1	1975	106.399	1	0	0	45.441	1.73	2.60
2	1976	110.549	1	0	0	48.398	1.65	2.54
3	1977	113.651	0	0	0	51.277	1.86	1.87
4	1978	116.439	0	0	0	53.557	1.85	1.83
5	1979	118.910	0	1	0	57.223	1.87	1.69
6	1980	121.094	0	0	0	55.531	1.70	1.45
7	1981	122.698	0	0	0	55.148	1.69	1.38
8	1982	124.206	0	0	0	54.795	1.74	1.13
9	1983	125.325	0	0	0	52.126	1.80	0.99
10	1984	126.300	0	0	0	54.063	1.77	1.06
11	1985	127.027	0	0	0	56.318	1.90	1.08
12	1986	127.676	0	0	0	56.598	1.90	1.19
13	1987	128.135	0	0	0	58.584	1.73	1.37
14	1988	128.973	0	0	0	62.192	1.62	1.44
15	1989	130.028	0	0	0	64.463	1.60	1.46
16	1990	131.085	0	0	0	67.153	1.56	1.48
17	1991	132.295	0	0	0	67.325	1.45	1.58
18	1992	133.840	0	0	0	69.779	1.40	1.61
19	1993	135.697	0	0	0	70.668	1.31	1.54
20	1994	137.435	0	0	0	73.217	1.27	1.53
21	1995	139.392	0	0	0	74.775	1.23	1.70
22	1996	140.844	0	0	0	75.944	1.17	1.58
23	1997	142.197	0	0	0	77.044	1.14	1.42

24	1998	142.598	0	0	0	79.052	1.12	1.54
25	1999	143.174	0	0	0	81.519	1.11	1.66
26	2000	143.652	0	0	1	83.786	1.06	1.32
27	2001	144.079	0	0	1	86.227	1.00	1.00
28	2002	144.632	0	0	1	90.012	0.98	1.40
29	2003	145.461	0	0	1	92.679	0.96	1.34
30	2004	146.447	0	0	1	95.606	0.93	1.31
31	2005	147.480	0	0	1	97.526	0.91	1.31
32	2006	148.560	0	0	1	99.470	0.91	1.31
33	2007	149.693	0	0	1	101.513	0.91	1.32
34	2008	150.863	0	0	1	103.453	0.91	1.32
35	2009	152.059	0	0	1	105.301	0.91	1.33

KENTUCKY POWER COMPANY
COMMERCIAL ENERGY SALES
EXOGENOUS VARIABLE

Obs	YEAR	CR_KPC	D7576	D79	DOOON	LCOM	PCNDX	GPCNDX
36	2010	153.277	0	0	1	107.154	0.91	1.33
37	2011	154.518	0	0	1	109.054	0.91	1.33
38	2012	155.800	0	0	1	111.234	0.91	1.31
39	2013	157.115	0	0	1	113.419	0.91	1.31
40	2014	158.450	0	0	1	115.524	0.91	1.30
41	2015	159.800	0	0	1	117.608	0.91	1.29
42	2016	161.159	0	0	1	119.653	0.91	1.29
43	2017	162.524	0	0	1	121.713	0.91	1.28
44	2018	163.891	0	0	1	123.732	0.91	1.26
45	2019	165.257	0	0	1	125.740	0.91	1.25
46	2020	166.617	0	0	1	127.718	0.91	1.22
47	2021	167.969	0	0	1	129.655	0.91	1.21
48	2022	169.310	0	0	1	131.578	0.91	1.20
49	2023	170.636	0	0	1	133.441	0.91	1.18

KENTUCKY POWER COMPANY
COMMERCIAL ENERGY SALES
MODEL ESTIMATION

The SYSLIN Procedure
Ordinary Least Squares Estimation

Model EC_KPC

Dependent Variable	EC_KPC
Label	ENERGY SALES, COMMERCIAL

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	6	1754561	292426.9	888.89	<.0001
Error	20	6579.627	328.9813		
Corrected Total	26	1761141			

Root MSE	18.13784	R-Square	0.99626
Dependent Mean	869.34124	Adj R-Sq	0.99514
Coeff Var	2.08639		

Parameter Estimates

Variable	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|	Variable Label
Intercept	1	-3673.80	180.0978	-20.40	<.0001	Intercept
LPCGPC5	1	-84.0992	50.54783	-1.66	0.1118	COM. ELEC./COM. GAS PRICE RATIO, LOG
CR_KPC	1	10.40594	3.570839	2.91	0.0086	RESIDENTIAL CUSTOMERS
LLCOM	I	776.1852	146.3918	5.30	<.0001	SERVICE AREA COMMERCIAL EMPLOYMENT, LOG
D7576	1	80.41701	18.29994	4.39	0.0003	BINARY VARIABLE, 1975 AND 1976
D79	1	-66.4091	20.99403	-3.16	0.0049	BINARY VARIABLE, 1979
DOOON	1	-25.0078	19.91973	-1.26	0.2238	BINARY VARIABLE, 2000 ON

KENTUCKY POWER COMPANY
COMMERCIAL ENERGY SALES
MODEL ESTIMATION

The SYSLIN Procedure
Ordinary Least Squares Estimation

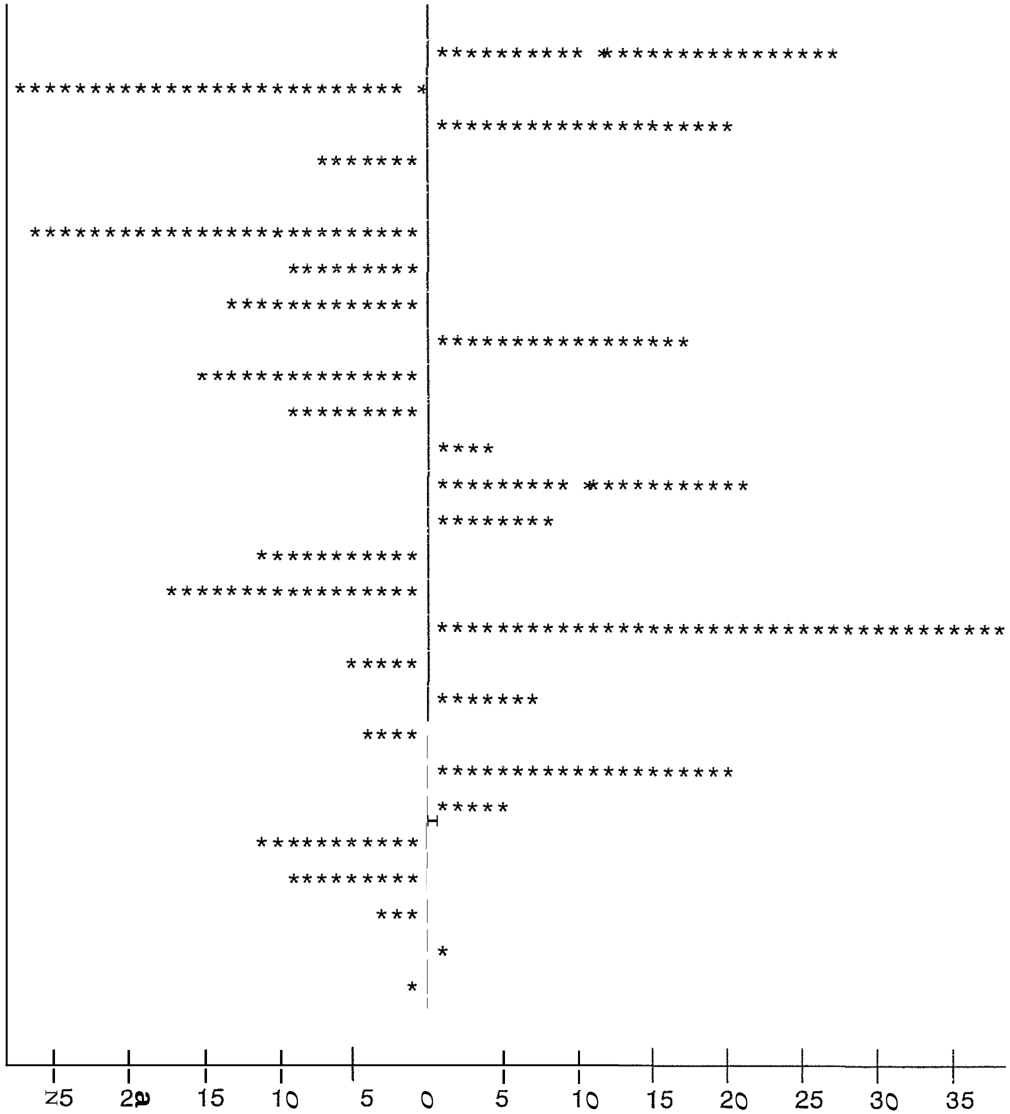
Durbin-Watson	2.478719
Number of Observations	27

First-Order Autocorrelation 0 2969

KENTUCKY POWER COMPANY

COMMERCIAL ENERGY SALES

MODEL RESIDUALS



Year	Residual Values Sum
1975	27 47971
1976	27 47971
1977	20 13527
1978	7 24736
1979	0 00000
1980	26 47253
1981	-8.71690
1982	-13 29260
1983	17 31797
1984	15 00597
1985	-9 49413
1986	3.89356
1987	20 72746
1988	7 79633
1989	10 82881
1990	17.36758
1991	37 70428
1992	-4 60998
1993	6 80745
1994	-3 87799
1995	19 71791
1996	5 02254
1997	10 66514
1998	-8 54265
1999	3 00159
2000	1 45425
2001	1 45425

KENTUCKY POWER COMPANY
COMMERCIAL ENERGY SALES
ACTUAL AND FORECAST

year	COMMERCIAL ENERGY SALES	GROWTH RATE
1975	420.20	
1976	461.77	9.9
1977	513.49	11.2
1978	554.89	8.1
1979	581.37	4.8
1980	630.95	8.5
1981	669.18	6.1
1982	685.51	2.4
1983	700.15	2.1
1984	714.59	2.1
1985	761.99	6.6
1986	786.15	3.2
1987	831.77	5.8
1988	869.40	4.5
1989	885.68	1.9
1990	919.62	3.8
1991	988.98	7.5
1992	991.36	0.2
1993	1034.39	4.3
1994	1072.37	3.7
1995	1134.51	5.8
1996	1150.45	1.4
1997	1165.68	1.3
1998	1194.52	2.5
1999	1230.93	3.0
2000	1243.52	1.0
2001	1278.78	2.8
2002	1321.98	3.4
2003	1358.08	2.7
2004	1398.88	3.0
2005	1427.77	2.1
2006	1450.78	1.6

2007	1480.64	2.1

KENTUCKY POWER COMPANY
COMMERCIAL ENERGY SALES
ACTUAL AND FORECAST

year	COMMERCIAL ENERGY SALES	GROWTH RATE
2008	1508.60	1.9
2009	1534.94	1.7
2010	1560.81	1.7
2011	1587.15	1.7
2012	1615.90	1.8
2013	1644.81	1.8
2014	1673.28	1.7
2015	1701.72	1.7
2016	1729.76	1.6
2017	1757.68	1.6
2018	1785.31	1.6
2019	1812.77	1.5
2020	1839.95	1.5
2021	1866.72	1.5
2022	1893.20	1.4
2023	1918.99	1.4

Long-term Industrial Models

KENTUCKY POWER COMPANY
MANUFACTURING ENERGY SALES
ENDOGENOUS VARIABLES

The MEANS Procedure

Variable	Label	Mean
YEAR	year	1999.00
EIX_KPC	ENERGY SALES, INDUSTRIAL EXCL MINEPOWER	1675.74

KENTUCKY POWER COMPANY
MANUFACTURING ENERGY SALES
ENDOGENOUS VARIABLES

Obs	YEAR	EIX_KPC
1	1975	1040.93
2	1976	1119.07
3	1977	1279.13
4	1978	1396.68
5	1979	1513.01
6	1980	1464.11
7	1981	1489.94
8	1982	1376.41
9	1983	1554.17
10	1984	1637.45
11	1985	1550.69
12	1986	1549.80
13	1987	1741.29
14	1988	1855.81
15	1989	1795.64
16	1990	1841.25
17	1991	1781.62
18	1992	1761.72
19	1993	1701.71
20	1994	1763.53
21	1995	1906.32
22	1996	1978.19
23	1997	2030.64

24	1998	2020.64
25	1999	2017.17
26	2000	2088.36
27	2001	1989.72
28	2002	
29	2003	
30	2004	
31	2005	
32	2006	
33	2007	
34	2008	
35	2009	

KENTUCKY POWER COMPANY
MANUFACTURING ENERGY SALES
ENDOGENOUS VARIABLES

Obs	YEAR	EIX_KPC
36	2010	
37	2011	
38	2012	
39	2013	
40	2014	
41	2015	
42	2016	
43	2017	
44	2018	
45	2019	
46	2020	
47	2021	
48	2022	
49	2023	

KENTUCKY POWER COMPANY
MANUFACTURING ENERGY SALES
EXOGENOUS VARIABLES

The MEANS Procedure

Variable	Label	Mean

YEAR	year	1999.00
LM_KPC	SERVICE AREA MANUFACTURING EMPLOYMENT	9.7701837
FRB28	I P CHEMICALS (1992=100 SA)	120.5985765
FRB29	I P PETROLEUM (1992=100 SA)	128.2769082
PIXNDX	REAL MAN. ELEC. PRICE INDEX, 2001=1.00	1,1546939
GPINDX	REAL KY MAN. GAS PRICE INDEX, 2001=1.00	0.7157143

KENTUCKY POWER COMPANY
MANUFACTURING ENERGY SALES
EXOGENOUS VARIABLES

Obs	YEAR	LM_KPC	FRB28	FRB29	PIXNDX	GPINDX
1	1975	13.046	60.338	88.020	1.39	0.27
2	1976	12.993	67.521	93.575	1.26	0.37
3	1977	13.652	72.366	101.504	1.49	0.45
4	1978	13.171	76.435	104.931	1.47	0.48
5	1979	13.541	79.205	103.912	1.44	0.53
6	1980	13.188	75.914	95.927	1.31	0.62
7	1981	12.640	77.294	91.169	1.40	0.68
8	1982	11.503	71.050	86.636	1.53	0.86
9	1983	11.074	75.955	86.870	1.56	0.95
10	1984	12.008	79.341	89.892	1.55	0.89
11	1985	11.806	79.436	89.498	1.76	0.89
12	1986	11.105	82.428	95.709	1.82	0.82
13	1987	11.654	87.050	96.975	1.60	0.69
14	1988	12.145	92.225	98.800	1.46	0.68
15	1989	12.019	95.100	99.275	1.39	0.69
16	1990	12.112	97.325	100.275	1.36	0.65
17	1991	12.181	96.375	99.100	1.38	0.58
18	1992	11.977	99.975	100.000	1.36	0.58
19	1993	11.423	100.950	102.850	1.23	0.65
20	1994	11.323	103.700	102.700	1.22	0.63
21	1995	11.529	105.975	104.500	1.14	0.55
22	1996	11.082	108.825	106.850	1.11	0.64
23	1997	11.100	115.850	111.025	1.08	0.69
24	1998	10.801	118.350	113.150	I.12	0.67
25	1999	10.120	119.100	113.425	1.15	0.56
26	2000	9.486	122.050	115.000	1.03	0.76
27	2001	8.519	121.175	114.300	1.00	1.00

28	2002	7.906	124.025	117.750	1.02	0.66
29	2003	7.804	128.225	125.100	0.94	0.68
30	2004	7.785	130.900	129.400	0.91	0.72
31	2005	7.718	133.625	132.550	0.90	0.74
32	2006	7.665	136.650	136.775	0.90	0.74
33	2007	7.617	139.450	140.775	0.90	0.74
34	2008	7.574	142.250	144.550	0.90	0.75
35	2009	7.535	145.050	148.150	0.90	0.75

KENTUCKY POWER COMPANY
MANUFACTURING ENERGY SALES
EXOGENOUS VARIABLES

Obs	YEAR	LM_KPC	FRB28	FRB29	PIXNDX	GPINDX
36	2010	7.498	147.850	151.850	0.9	0.76
37	2011	7.457	150.650	155.550	0.9	0.77
38	2012	7.421	153.675	159.400	0.9	0.78
39	2013	7.377	156.650	163.425	0.9	0.79
40	2014	7.317	159.525	167.600	0.9	0.79
41	2015	7.259	162.700	171.750	0.9	0.80
42	2016	7.194	165.900	176.150	0.9	0.80
43	2017	7.124	169.100	180.550	0.9	0.81
44	2018	7.059	172.300	184.950	0.9	0.82
45	2019	6.988	175.500	189.350	0.9	0.84
46	2020	6.916	178.700	193.825	0.9	0.86
47	2021	6.846	181.900	198.600	0.9	0.87
48	2022	6.775	185.100	203.400	0.9	0.88
49	2023	6.706	188.300	208.250	0.9	0.89

KENTUCKY POWER COMPANY
MANUFACTURING ENERGY SALES
MODEL ESTIMATION

The SYSLIN Procedure
Ordinary Least Squares Estimation

Model	**LEIX**
Dependent Variable	LEIX
Label	

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	4	0.830298	0.207574	207.03	<.0001
Error	22	0.022058	0.001003		
Corrected Total	26	0.852355			

Root MSE	0.03166	R-Square	0.97412
Dependent Mean	7.40902	Adj R-Sq	0.96942
Coeff Var	0.42737		

Parameter Estimates

Variable	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|	Variable Label
Intercept	1	1.826813	0.703155	2.60	0.0164	Intercept
LPIXGPI5	1	-0.38033	0.058278	-6.53	<.0001	MANUF. ELEC./IND. GAS PRICE RATIO, LOG
LFRB28	1	0.523292	0.129319	4.05	0.0005	FRB IND. PROD.-CHEMICALS, LOG
LFRB29	1	0.373044	0.223335	1.67	0.1090	FRB IND. PROD.-PETROLEUM, LOG
LLM	1	0.600092	0.109304	5.49	<.0001	SERVICE AREA MANUFACTURING EMPLOYMENT, LOG

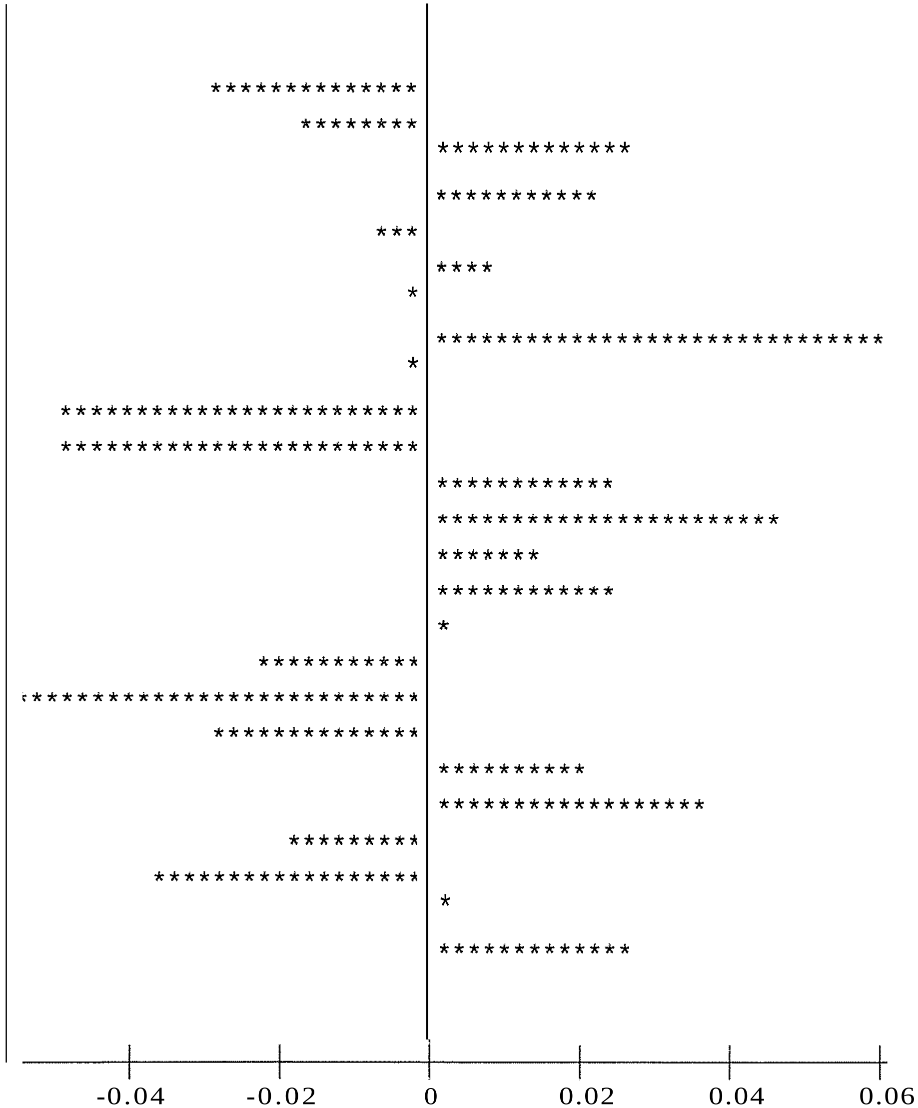
KENTUCKY POWER COMPANY
MANUFACTURING ENERGY SALES
MODEL ESTIMATION

The SYSLIN Procedure
Ordinary Least Squares Estimation

Durbin-Watson	1.422061
Number of Observations	27
First-Order Autocorrelation	0.288967

KENTUCKY POWER COMPANY
MANUFACTURING ENERGY SALES
MODEL RESIDUALS

year Residual Values



Year	Sum
1975	-0.000340
1976	-0.027915
1977	-0.016481
1978	0.025927
1979	0.022257
1980	-0.006441
1981	0.008722
1982	-0.001159
1983	0.059379
1984	-0.002719
1985	-0.048060
1986	-0.048556
1987	0.023989
1988	0.046243
1989	0.013717
1990	0.024277
1991	0.001490
1992	-0.022073
1993	-0.053295
1994	-0.028836
1995	0.020031
1996	0.035292
1997	-0.018006
1998	-0.035344
1999	0.002673
2000	0.025285
2001	-0.000056

Residual Values

KENTUCKY POWER COMPANY

MANUFACTURING ENERGY SALES

ACTUAL AND FORECAST

ENERGY GROWTH

year	SALES	RATE
1975	1040.93	
1976	1119.07	7.5
1977	1279.13	14.3
1978	1396.68	9.2
1979	1513.01	8.3
1980	1464.11	-3.2
1981	1489.94	1.8
1982	1376.41	-7.6
1983	1554.17	12.9
1984	1637.45	5.4
1985	1550.69	-5.3
1986	1549.80	-0.1
1987	1741.29	12.4
1988	1855.81	6.6
1989	1795.64	-3.2
1990	1841.25	2.5
1991	1781.62	-3.2
1992	1761.72	-1.1
1993	1701.71	-3.4
1994	1763.53	3.6
1995	1906.32	8.1
1996	1978.19	3.8
1997	2030.64	2.7
1998	2020.64	-0.5
1999	2017.17	-0.2
2000	2088.36	3.5
2001	1989.72	-4.7
2002	1949.83	-2.0
2003	2042.27	4.7
2004	2160.80	5.8
2005	2209.61	2.3
2006	2210.80	0.1
2007	2291.98	3.7

KENTUCKY POWER COMPANY
MANUFACTURING ENERGY SALES
ACTUAL AND FORECAST

year	ENERGY SALES	GROWTH RATE
2008	2354.71	2.7
2009	2404.86	2.1
2010	2449.48	1.9
2011	2494.63	1.8
2012	2545.52	2.0
2013	2595.14	1.9
2014	2641.05	1.8
2015	2689.93	1.9
2016	2737.34	1.8
2017	2783.01	1.7
2018	2830.37	1.7
2019	2877.94	1.7
2020	2928.45	1.8
2021	2981.67	1.8
2022	3035.83	1.8
2023	3089.61	1.8

KENTUCKY POWER COMPANY
MINE POWER ENERGY SALES
ENDOGENOUS VARIABLES

The MEANS Procedure

Variable	Label	Mean
year	year	1999.00
EIM_KPC	ENERGY SALES, MINEPOWER	900.3551461

KENTUCKY POWER COMPANY
MINE POWER ENERGY SALES
ENDOGENOUS VARIABLES

Obs	year	EIM_KPC
1	1975	405.11
2	1976	463.02
3	1977	508.13
4	1978	554.16
5	1979	718.16
6	1980	763.27
7	1981	805.88
8	1982	851.29
9	1983	812.71
10	1984	851.19
11	1985	890.55
12	1986	881.70
13	1987	902.84
14	1988	911.86
15	1989	984.60
16	1990	1041.79
17	1991	1039.88
18	1992	1057.46
19	1993	1084.54
20	1994	1106.37
21	1995	1073.92
22	1996	1098.18
23	1997	1111.15

24	1998	1110.13
25	1999	1073.99
26	2000	1071.03
27	2001	1136.68
28	2002	
29	2003	
30	2004	
31	2005	
32	2006	
33	2007	
34	2008	
35	2009	

KENTUCKY POWER COMPANY
MINE POWER ENERGY SALES
ENDOGENOUS VARIABLES

Obs	year	EIM_KPC
36	2010	
37	2011	
38	2012	
39	2013	
40	2014	
41	2015	
42	2016	
43	2017	
44	2018	
45	2019	
46	2020	
47	2021	
48	2022	
49	2023	

KENTUCKY POWER COMPANY
MINE POWER ENERGY SALES
EXOGENOUS VARIABLES

The MEANS Procedure

Variable	Label	Mean

YEAR	year	1999.00
qc_kpc	SERVICE AREA COAL PRODUCTION	96.4645510
D900N	BINARY VARIABLE-I990 ON	0.6938776
DO1ON	BINARY VARIABLE-2001 ON	0.4693878
PIMNDX	REAL MINE PWR ELC PRICE INDX, 2001=1.00	1.3348980
OILNDX	REAL OIL PRICE INDEX, 2001=1.00	0.9889796

KENTUCKY POWER COMPANY
MINE POWER ENERGY SALES
EXOGENOUS VARIABLES

Obs	YEAR	qc_kpc	D900N	D01ON	PIMNDX	OILNDX
1	1975	61.239	0	0	2.04	0.82
2	1976	65.348	0	0	1.90	0.85
3	1977	68.948	0	0	2.15	0.92
4	1978	68.312	0	0	2.12	0.89
5	1979	77.628	0	0	2.02	1.14
6	1980	79.085	0	0	1.84	1.47
7	1981	86.782	0	0	1.93	1.69
8	1982	85.8	0	0	1.96	1.59
9	1983	71.398	0	0	2.03	1.38
10	1984	92.824	0	0	2.03	1.34
11	1985	96.575	0	0	2.25	1.26
12	1986	93.447	0	0	2.27	0.80
13	1987	98.195	0	0	2.01	0.87
14	1988	93.387	0	0	1.84	0.74
15	1989	103.173	0	0	1.73	0.82
16	1990	106.278	1	0	1.67	1.00
17	1991	95.82	1	0	1.56	0.89
18	1992	98.315	1	0	1.46	0.84
19	1993	108.345	1	0	1.34	0.79
20	1994	105.291	?	0	1.30	0.74
21	1995	100.661	1	0	1.34	0.72
22	1996	99.131	1	0	1.10	0.87
23	1997	104.513	1	0	1.13	0.81
24	1998	106.292	1	0	1.09	0.61
25	1999	98.25	1	0	1.12	0.71
26	2000	93.927	1	0	1.02	1.12
27	2001	93.501	1	1	1.00	1.00

28	2002	92.364	1	1	0.98	0.94
29	2003	94.63	1	1	0.96	0.97
30	2004	95.943	1	1	0.93	0.86
31	2005	97.773	1	1	0.91	0.83
32	2006	99.241	1	1	0.91	0.84
33	2007	100.987	1	1	0.91	0.82
34	2008	101.538	1	1	0.91	0.84
35	2009	102.05	1	1	0.91	0.86

KENTUCKY POWER COMPANY
MINE POWER ENERGY SALES
EXOGENOUS VARIABLES

Obs	YEAR	qc_kpc	D900N	D010N	PIMNDX	OILNDX
36	2010	102.458	1	1	0.91	0.89
37	2011	102.774	1	1	0.91	0.91
38	2012	103.312	1	1	0.91	0.95
39	2013	103.779	1	1	0.91	0.98
40	2014	104.275	1	1	0.91	1.01
41	2015	104.917	1	1	0.91	1.03
42	2016	105.667	1	1	0.91	1.06
43	2017	106.549	1	1	0.91	1.08
44	2018	107.226	1	1	0.91	1.11
45	2019	108.064	1	1	0.91	1.13
46	2020	108.971	1	1	0.91	1.14
47	2021	109.782	1	1	0.91	1.16
48	2022	110.593	1	1	0.91	1.18
49	2023	111.405	1	1	0.91	1.19

KENTUCKY POWER COMPANY
MINE POWER ENERGY SALES
MODEL ESTIMATION

The SYSLIN Procedure
Ordinary Least Squares Estimation

Model	LEIM
Dependent Variable	LEIM
Label	

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	4	0.399614	0.099903	64.98	<.0001
Error	18	0.027675	0.001537		
Corrected Total	22	0.427289			

Root MSE	0.03921	R-Square	0.93523
Dependent Mean	6.87135	Adj R-Sq	0.92084
Coeff Var	0.57064		

Parameter Estimates

Variable	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|	Variable Label
Intercept	1	4.093243	0.453833	9.02	<.0001	Intercept
LQC	1	0.625122	0.103363	6.05	<.0001	SERVICE AREA COAL PRODUCTION, LOG
LPIMOIL5	1	-0.08768	0.051559	-1.70	0.1062	RATIO 5YR MVNG AVE ELEC TO OIL PRICE, LOG
D90ON	1	0.154500	0.021848	7.07	<.0001	BINARY VARIABLE-1990 ON
D01ON	1	0.075747	0.044204	1.71	0.1038	BINARY VARIABLE-2001 ON

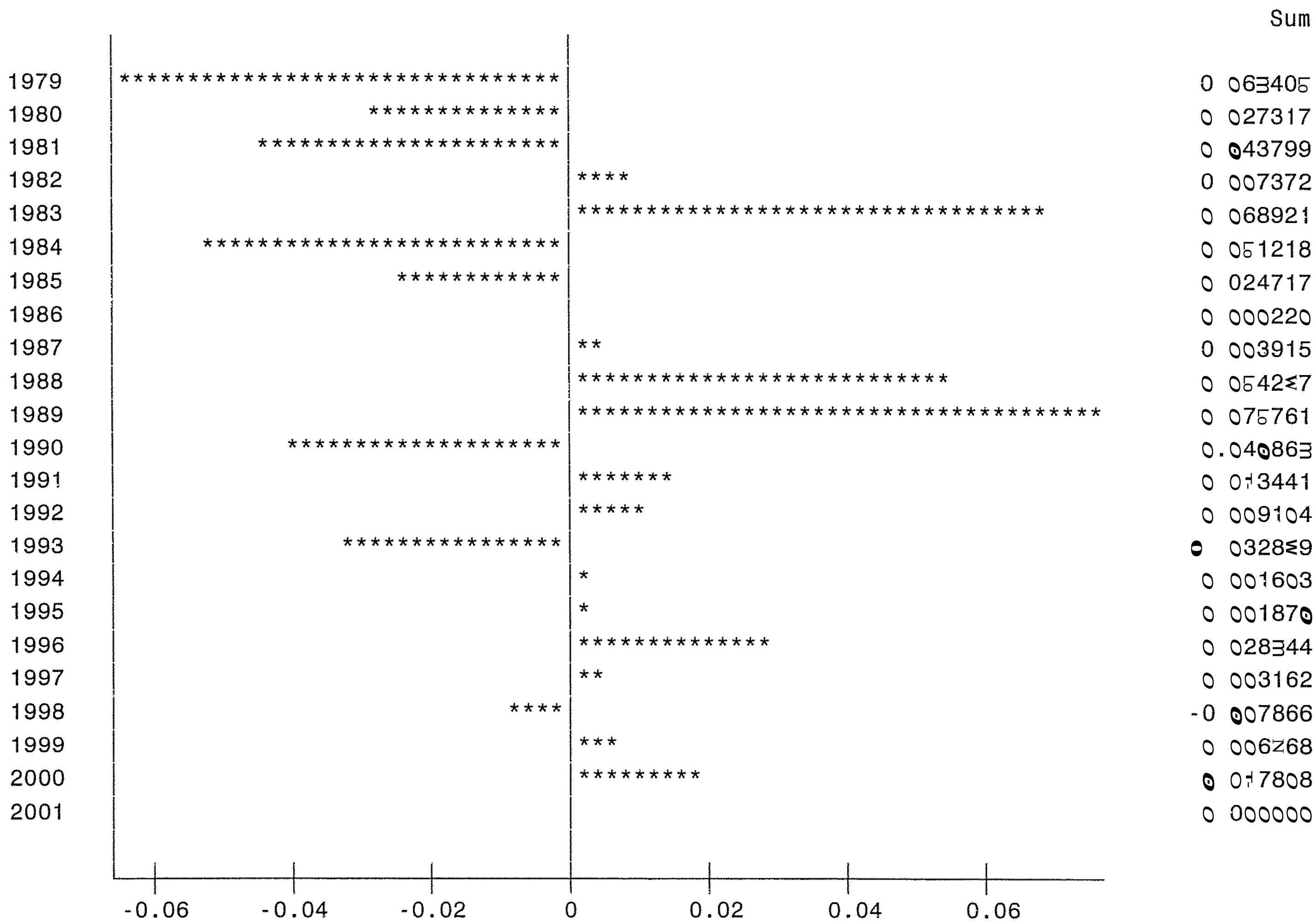
KENTUCKY POWER COMPANY
MINE POWER ENERGY SALES
MODEL ESTIMATION

The SYSLIN Procedure
Ordinary Least Squares Estimation

Durbin-Watson	1.747979
Number of Observations	23
First-Order Autocorrelation	0.053378

KENTUCKY POWER COMPANY
MINE POWER ENERGY SALES
MODEL RESIDUALS

year	Residual Values



Residual Values
KENTUCKY POWER COMPANY
MINE POWER ENERGY SALES
ACTUAL AND FORECAST

year	ENERGY SALES	GROWTH RATE
1975	4 0.11	.
1976	4 8.02	14.3

1977	508.13	9.7
1978	554.16	9.1
1979	718.16	29.6
1980	763.27	6.3
1981	805.88	5.6
1982	851.29	5.6
1983	812.71	-4.5
1984	851.19	4.7
1985	890.55	4.6
1986	881.70	-1.0
1987	902.84	2.4
1988	911.86	1.0
1989	984.60	8.0
1990	1041.79	5.8
1991	1039.88	-0.2
1992	1057.46	1.7
1993	1084.54	2.6
1994	1106.37	2.0
1995	1073.92	-2.9
1996	1098.18	2.3
1997	1111.15	1.2
1998	1110.13	-0.1
1999	1073.99	-3.3
2000	1071.03	-0.3
2001	1136.68	6.1
2002	1133.87	-0.2
2003	1161.81	2.5
2004	1178.90	1.5
2005	1189.01	0.9
2006	1198.44	0.8
2007	1210.28	1.0

KENTUCKY POWER COMPANY
MINE POWER ENERGY SALES
ACTUAL AND FORECAST

year	ENERGY SALES	GROWTH RATE
2008	'212.08	0.1

2009	1216.42	0.4
2010	1220.78	0.4
2011	1224.91	0.3
2012	1232.00	3.6
2013	1238.88	0.6
2014	1246.05	0.6
2015	1254.24	0.7
2016	1263.10	0.7
2017	1272.69	0.8
2018	1280.48	0.6
2019	1289.22	0.7
2020	1298.26	0.7
2021	1306.38	0.6
2022	1314.31	0.6
2023	1322.08	0.6

Long-term Other Energy Models

Kentucky Power Company
Public Street and Highway Lighting
ENDOGENOUS VARIABLES

The MEANS Procedure

Variable	Label	Mean
year	year	1999.00
EUL_KPC	ENERGY SALES, STREET LIGHTS	8.9378085

Kentucky Power Company
Public Street and Highway Lighting
ENDOGENOUS VARIABLES

Obs	year	EUL_KPC
1	1975	7.2010
2	1976	7.4610
3	1977	7.6490
4	1978	7.9130
5	1979	8.0900
6	1980	8.2200
7	1981	8.0140
8	1982	7.9330
9	1983	8.1330
10	1984	8.2270
11	1985	8.3520
12	1986	8.3420
13	1987	8.4120
14	1988	8.6190
15	1989	8.5130
16	1990	8.6820
17	1991	9.0950
18	1992	9.1860
19	1993	9.4200
20	1994	9.6360
21	1995	10.0820
22	1996	9.9100
23	1997	10.3133

24	1998	10.5297
25	1999	10.6362
26	2000	11.4358
27	2001	11.3160
28	2002	
29	2003	
30	2004	
31	2005	
32	2006	
33	2007	
34	2008	
35	2009	

Kentucky Power Company

Public Street and Highway Lighting

ENDOGENOUS VARIABLES

Obs	year	EUL_KPC
36	2010	
37	2011	
38	2012	
39	2013	
40	2014	
41	2015	
42	2016	
43	2017	
44	2018	
45	2019	
46	2020	
47	2021	
48	2022	
49	2023	

Kentucky Power Company

Public Street and Highway Lighting

EXOGENOUS VARIABLES

The MEANS Procedure

Variable	Label	Mean

year	year	1999.00
D01ON	BINARY VARIABLE-1999 ON	0.4693878
LCOM	SERVICE AREA COMMERCIAL EMPLOYMENT	85.8160408

Kentucky Power Company
Public Street and Highway Lighting
EXOGENOUS VARIABLES

Obs	year	D01ON	LCOM
1	1975	0	45.441
2	1976	0	48.398
3	1977	0	51.277
4	1978	0	53.557
5	1979	0	57.223
6	1980	0	55.531
7	1981	0	55.148
8	1982	0	54.795
9	1983	0	52.126
10	1984	0	54.063
11	1985	0	56.318
12	1986	0	56.598
13	1987	0	58.584
14	1988	0	62.192
15	1989	0	64.463
16	1990	0	67.153
17	1991	0	67.325
18	1992	0	69.779
19	1993	0	70.668
20	1994	0	73.217
21	1995	0	74.775
22	1996	0	75.944
23	1997	0	77.044
24	1998	0	79.052
25	1999	0	81.519
26	2000	0	83.786
27	2001	1	86.227
28	2002	1	90.012
29	2003	1	92.679
30	2004	1	95.606

31	2005	1	97.526
32	2006	1	99.470
33	2007	1	101.513
34	2008	1	103.453
35	2009	1	105.301

Kentucky Power Company
Public Street and Highway Lighting
EXOGENOUS VARIABLES

Obs	year	D010N	LCOM
36	2010	I	107.154
37	2011	1	109.054
38	2012	1	111.234
39	2013	1	113.419
40	2014	1	115.524
41	2015	1	117.608
42	2016	1	119.653
43	2017	1	121.713
44	2018	1	123.732
45	2019	1	125.740
46	2020	1	127.718
47	2021	1	129.655
48	2022	1	131.578
49	2023	1	133.441

Kentucky Power Company
Public Street and Highway Lighting
EXOGENOUS VARIABLES
MODEL ESTIMATION

The SYSLIN Procedure
Ordinary Least Squares Estimation

Model	EUL_KPC
Dependent Variable	EUL_KPC
Label	ENERGY SALES, STREET LIGHTS

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	2	34.31015	17.15508	286.49	<.0001
Error	24	1.437128	0.059880		
Corrected Total	26	35.74728			

Root MSE	0.24470	R-Square	0.95980
Dependent Mean	8.93781	Adj R-Sq	0.95645
Coeff Var	2.73786		

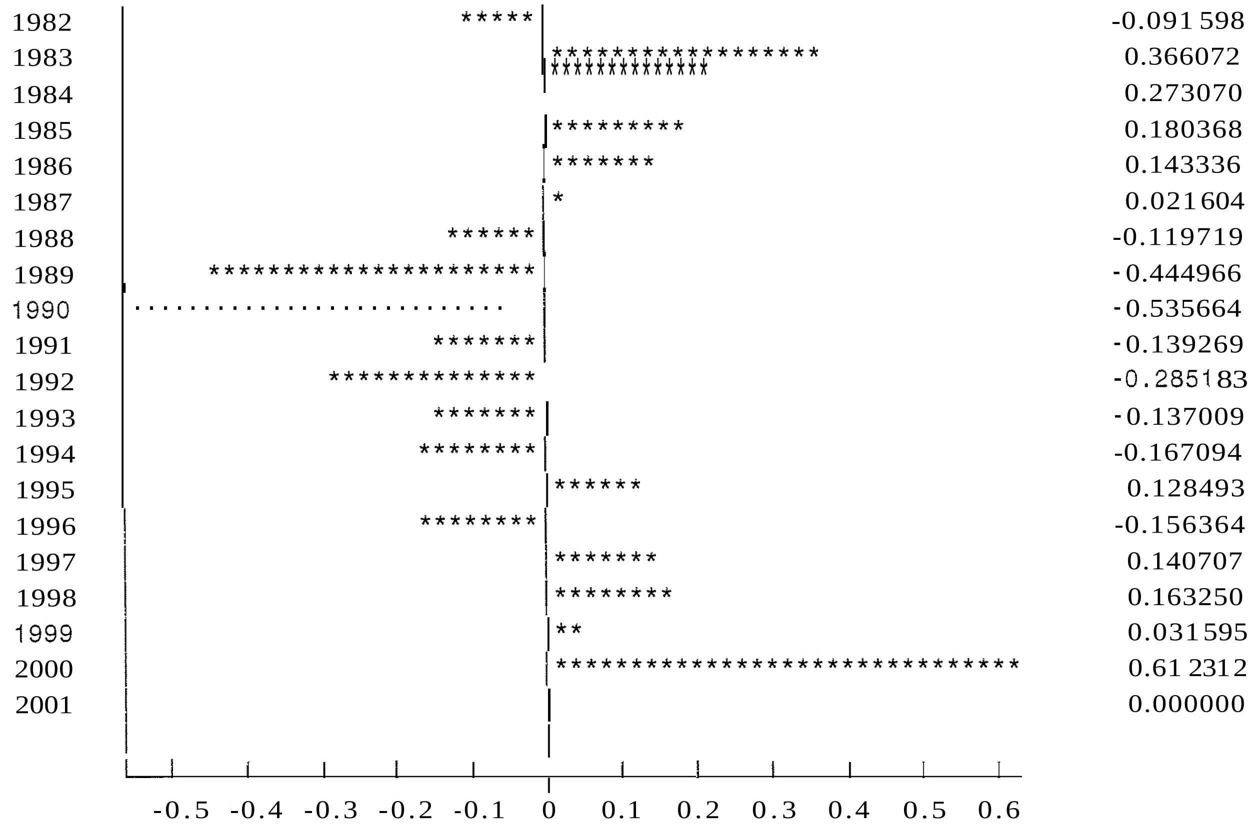
Parameter Estimates

Variable	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|	Variable Label
Intercept	1	2.734582	0.234533	[illegible].61	<.0001	Intercept
LCOM	1	0.096542	0.004430	21.79	<.0001	SERVICE AREA COMMERCIAL EMPLOYMENT
D01ON	1	0.256851	0.269247	0.95	0.3496	BINARY VARIABLE-1999 ON

Durbin-Watson	1.199417
Number of Observations	27
First-Order Autocorrelation	0.398095

Kentucky Power Company
Public Street and Highway Lighting
MODEL RESIDUALS

year			Residual Values Sum
1975		****	0.079455
1976		***	0.053981
1977	*		-0.035964
1978			0.007921
1979	**** **		-0.169002
1980		*****	0.124347
1981	**		-0.044678



Residual Values
Kentucky Power Company
Public Street and Highway Lighting
ACTUAL AND FORECAST

year	ENERGY SALES	GROWTH RATE
1975	7.2010	
1976	7.4610	3.6
1977	7.6490	2.5
1978	7.9130	3.5
1979	8.0900	2.2
1980	8.2200	1.6
1981	8.0140	2.5

1982	[illegible].9330	-1.0
1983	8.1330	2.5
1984	8.2270	1.2
1985	8.3520	1.5
1986	8.3420	-0.1
1987	8.4120	0.8
1988	8.6190	2.5
1989	8.5130	-1.2
1990	8.6820	2.0
1991	9.0950	4.8
1992	9.1860	1.0
1993	9.4200	2.5
1994	9.6360	2.3
1995	10.0820	4.6
1996	9.9100	-1.7
1997	10.3133	4.1
1998	10.5297	2.1
1999	10.6362	1.0
2000	11.4358	7.5
2001	11.3160	-1.0
2002	11.6814	3.2
2003	11.9388	2.2
2004	12.2214	2.4
2005	12.4068	1.5
2006	12.5945	1.5
2007	12.7917	1.6

Kentucky Power Company

Public Street and Highway Lighting

ACTUAL AND FORECAST

year	ENERGY SALES	GROWTH RATE
2008	12.9790	1.5
2009	13.1574	1.4
2010	13.3363	1.4
2011	13.5197	1.4
2012	13.7302	I.6
2013	13.9411	1.5

2014	14.1443	1.5
2015	14.3455	1.4
2016	14.5430	1.4
2017	14.7418	1.4
2018	14.9368	1.3
2019	15.1306	1.3
2020	15.3216	1.3
2021	15.5086	1.2
2022	15.6942	1.2
2023	15.8741	1.1

Kentucky Power Company
Municipals
Endogenous Variables

The MEANS Procedure

Variable	Label	Mean
year	year	1999.00
EOM_KPC	ENERGY SALES, MUNICIPALS	45.5933630

Kentucky Power Company
Municipals
Endogenous Variables

Obs	year	EOM_KPC
1	1975	31.7010
2	1976	33.7880
3	1977	36.9300
4	1978	40.1730
5	1979	42.3070
6	1980	45.7910
7	1981	46.1420
8	1982	45.6340
9	1983	29.9500
10	1984	19.8690
11	1985	20.0080
12	1986	20.0330
13	1987	21.2340
14	1988	21.9830
15	1989	29.3030
16	1990	26.7030
17	1991	30.9370
18	1992	26.4040
19	1993	27.7690
20	1994	73.4120
21	1995	78.2850
22	1996	82.6310
23	1997	78.7232

24	1998	80.5080
25	1999	80.7454
26	2000	80.7977
27	2001	79.2595
28	2002	
29	2003	
30	2004	
31	2005	
32	2006	
33	2007	
34	2008	
35	2009	

Kentucky Power Company

Municipals

Endogenous Variables

Obs	year	EOM_KPC
36	2010	
37	2011	
38	2012	
39	2013	
40	2014	
41	2015	
42	2016	
43	2017	
44	2018	
45	2019	
46	2020	
47	2021	
48	2022	
49	2023	

Kentucky Power Company

Municipals

EXOGENOUS VARIABLES

The MEANS Procedure

Variable	Label	Mean

year	year	1999.00
L_KPC		132.8100000
HDD_hunt	huntOKE HEATING DEGREE DAYS	4523.04
CDD_hunt	huntOKE COOLING DEGREE DAYS	1170.54
D94ON	BINARY VARIABLE-1994 ON	0.6122449
D01ON	BINARY VARIABLE-2001 ON	0.4693878
LCOM	SERVICE AREA COMMERCIAL EMPLOYMENT	85.8160408

Kentucky Power Company
Municipals
EXOGENOUS VARIABLES

Obs	year	L_KPC	HDD_hunt	CDD_hunt	D94ON	D01ON	LCOM
1	1975	95.261	4249.00	1274.00	0	0	45.441
2	1976	98.510	4736.00	867.00	0	0	48.398
3	1977	103.072	4754.00	1373.00	0	0	51.277
4	1978	107.705	5150.00	1308.00	0	0	53.557
5	1979	113.643	4753.00	1004.00	0	0	57.223
6	1980	111.217	5021.00	1310.00	0	0	55.531
7	1981	111.092	4847.00	1138.00	0	0	55.148
8	1982	108.646	4502.00	822.00	0	0	54.795
9	1983	99.789	4683.00	1374.00	0	0	52.126
10	1984	104.823	4452.00	1193.00	0	0	54.063
11	1985	106.334	4502.00	1047.00	0	0	56.318
12	1986	105.546	4258.00	1360.00	0	0	56.598
13	1987	107.886	4409.00	1366.00	0	0	58.584
14	1988	110.905	4852.00	1217.00	0	0	62.192
15	1989	113.335	4828.00	1080.00	0	0	64.463
16	990	17.613	3627.00	1165.00	0	0	67.153
17	991	16.774	3975.00	1670.00	0	0	67.325
18	992	18.813	4401.00	942.00	0	0	69.779
19	993	18.786	4587.00	1294.00	0	0	70.668
20	994	21.273	4362.00	1100.00	1	0	73.217
21	995	22.499	4733.00	1264.00	1	0	74.775
22	1996	122.225	4878.00	1087.00	1	0	75.944
23	1997	123.711	4708.00	839.00	1	0	77.044
24	1998	125.778	3869.00	1267.00	1	0	79.052
25	1999	127.284	4197.00	1244.00	1	0	81.519
26	2000	127.987	4603.00	978.00	1	0	83.786

W5

27	2001	130.784	4264.00	1120.00	1	1	86.227
28	2002	134.450	4519.50	1166.07	1	1	90.012
29	2003	136.966	4519.50	1166.07	1	1	92.679
30	2004	139.962	4519.50	1166.07	1	1	95.606
31	2005	141.744	4519.50	1166.07	1	1	97.526
32	2006	143.612	4519.50	1166.07	1	1	99.470
33	2007	145.626	4519.50	1166.07	1	1	101.513
34	2008	147.533	4519.50	1166.07	1	1	103.453
35	2009	149.327	4519.50	1166.07	1	1	105.301

Kentucky Power Company

Municipals

EXOGENOUS VARIABLES

Obs	year	L_KPC	HDD_hunt	CDD_hunt	D94ON	DO1ON	LCOM
36	2010	151.142	4519.50	1166.07	1	1	107.154
37	2011	153.018	4519.50	1166.07	1	1	109.054
38	2012	155.215	4519.50	1166.07	1	1	111.234
39	2013	157.350	4519.50	1166.07	1	1	113.419
40	2014	159.390	4519.50	1166.07	1	1	115.524
41	2015	161.401	4519.50	1166.07	1	1	117.608
42	2016	163.369	4519.50	1166.07	1	1	119.653
43	2017	165.320	4519.50	1166.07	1	1	121.713
44	2018	167.241	4519.50	1166.07	1	1	123.732
45	2019	169.136	4519.50	1166.07	1	1	125.740
46	2020	170.979	4519.50	1166.07	1	1	127.718
47	2021	172.778	4519.50	1166.07	1	1	129.655
48	2022	174.569	4519.50	1166.07	1	1	131.578
49	2023	176.271	4519.50	1166.07	1	1	133.441

Kentucky Power Company

Municipals

MODEL ESTIMATION

The SYSLIN Procedure

Ordinary Least Squares Estimation

Model	EOM_KPC
Dependent: Variable	EOM_KPC
Label	ENERGY SALES, MUNICIPALS

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	5	13529.81	2705.962	486.71	<.0001
Error	12	66.71637	5.559697		
Corrected Total	17	13596.53			

Root MSE	2.35790	R-Square	0.99509
Dependent Mean	48.81138	Adj R-Sq	0.99305
Coeff Var	4.83064		

Parameter Estimates

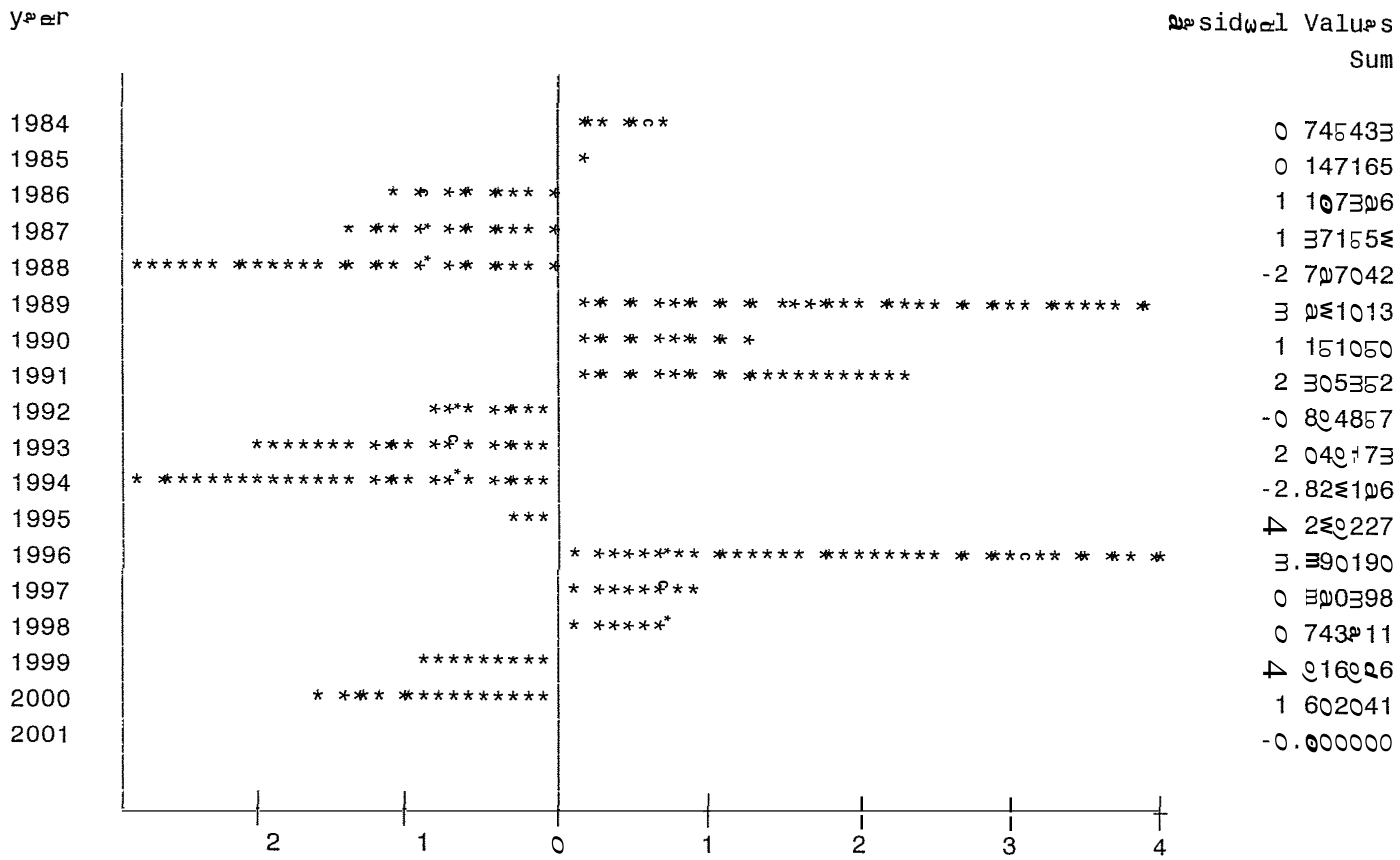
Variable	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|	Variable Label
Intercept	1	-26.2422	14.40838	-1.82	0.0936	Intercept
LCOM	1	0.601927	0.119190	5.05	0.0003	SERVICE AREA COMMERCIAL EMPLOYMENT
D94ON	1	46.17475	2.181441	21.17	<.0001	BINARY VARIABLE-1994 ON
D01ON	1	-4.74923	2.704468	-1.76	0.1045	BINARY VARIABLE-2001 ON
HDD_hunt	1	0.001596	0.001874	0.85	0.4111	huntOKE HEATING DEGREE DAYS
CDD_hunt	1	0.004794	0.003536	1.36	0.2002	huntOKE COOLING DEGREE DAYS

Kentucky Power Company
Municipals
MODEL ESTIMATION

The SYSLIN Procedure
Ordinary Least Squares Estimation

Durbin-Watson	1.637077
Number of Observations	18
First-Order Autocorrelation	0.177297

Kentucky Power Company
Municipals
MODEL RESIDUALS



Residual Values
Kentucky Power Company
Municipals
ACTUAL AND FORECAST

year	ENERGY SALES	GROWTH RATE
1984	19.8690	.
1985	20.0080	0.7
1986	20.0330	0.1
1987	21.2340	6.0
1988	21.9830	3.5

1989	2s.3030	33.3
1990	26.7030	-8.9
1991	30.9370	15.9
1992	26.4040	-14.7
1993	27.7690	5.2
1994	73.4120	164.4
1995	78.2850	6.6
1996	82.6310	5.6
1997	78.7232	-4.7
1998	80.5080	2.3
1999	80.7454	0.3
2000	80.7977	0.1
2001	79.2595	-1.9
2002	82.1660	3.7
2003	83.7720	2.0
2004	85.5340	2.1
2005	86.6890	1.4
2006	0.0000	-100.0
2007	0.0000	
2008	0.0000	
2009	0.0000	
2010	0.0000	
2011	0.0000	
2012	0.0000	
2013	0.0000	
2014	0.0000	
2015	0.0000	
2016	0.0000	

Kentucky Power Company

Municipals

ACTUAL AND FORECAST

year	ENERGY SALES	GROWTH RATE
2017	0	
2018	0	
2019	0	
2020	0	

2021
2022
2023

Peak Demand

Obs	YEAR	KPC_TOTL
1	1997	1353.07
2	1998	1398.81
3	1999	1412.71
4	2000	1433.28
5	2001	1473.33
6	2002	1484.77
7	2003	1502.52
8	2004	1554.12
9	2005	1591.82
10	2006	1602.72
11	2007	1641.31
12	2008	1668.33
13	2009	1701.05
14	2010	1727.00
15	2011	1754.97
16	2012	1776.40
17	2013	1812.43
18	2014	1841.82
19	2015	1872.15
20	2016	1896.63
21	2017	1930.06
22	2018	1959.46
23	2019	1990.07
24	2020	2015.01
25	2021	2052.41
26	2022	2085.28
27	2023	2112.09

Obs	DATE	HOUR	KPC_TOTL	OLIV_ TOTL	VANC_ TOTL	YEAR
1	013197	9	1353.07			1997
2	013098	9	1398.81		.	1998
3	012999	9	1412.71			1999
4	012800	9	1433.28	3.74400	11.8060	2000
5	020201	9	1473.33	3.38700	11.3600	2001
6	020102	9	1484.77	3.34516	12.2237	2002
7	013103	9	1502.52	3.34405	12.5399	2003
8	013004	9	1554.12	3.35737	12.8118	2004
9	012805	9	1591.82	3.37189	13.1010	2005
10	020306	9	1586.10	3.35864	13.2690	2006
11	020207	9	1624.44	3.36325	13.5105	2007
12	020108	9	1651.26	3.35687	13.7107	2008
13	013009	9	1683.72	3.36500	13.9660	2009
14	012910	9	1709.44	3.36474	14.1902	2010
15	012811	9	7737.18	3.36638	14.4316	2011
16	020312	9	1758.47	3.35011	14.5753	2012
17	020113	9	1794.18	3.36811	14.8831	2013
18	013114	9	1823.31	3.37288	15.1304	2014
19	013015	9	1853.41	3.37589	15.3663	2015
20	012916	9	1877.69	3.37002	15.5714	2016
21	020317	9	1910.89	3.37151	15.8015	2017
22	020218	9	1940.05	3.37526	16.0430	2018
23	020119	9	1970.41	3.37836	16.2849	2019
24	013120	9	1995.17	3.37035	16.4677	2020
25	012921	9	2032.28	3.38185	16.7543	2021
26	012822	9	2064.89	3.38451	17.0018	2022
27	020323	9	2091.58	3.36962	17.1457	2023

Obs	YEAR	KPC_TOTL
1	1997	7181922.15
2	1998	7171098.35
3	1999	7116040.51
4	2000	7392024.61

5	2001	7396120.16
6	2002	7612743.12
7	2003	7702032.22
8	2004	7993303.33
9	2005	8150140.46
10	2006	8125290.57
11	2007	8322230.00
12	2008	8480056.60
13	2009	8619631.78
14	2010	8750423.86
15	2011	8884337.94
16	2012	9037116.30
17	2013	9188713.64
18	2014	9335895.33
19	2015	9488546.48
20	2016	9639616.52
21	2017	9789719.09
22	2018	9939615.13
23	2019	10091500.76
24	2020	10246819.09
25	2021	10403443.09
26	2022	10560866.49
27	2023	10715707.14

Data Glossary, Short-term Energy Models

Kentucky Power Company

Short-Term Energy Models
Data Glossary

Endogenous Variables

revcls – 1	Residential Energy Sales (KWH)
revcls – 2	Commercial Energy Sales (KWH)
revcls – 3	Industrial Energy Sales (KWH)
revcls – 4	Other Retail Energy Sales (KWH) (Public Street and Highway Lighting)
revcls – 5	Energy Sales to Municipals (KWH)
revcls – 1	Residential Customers (CUST)
revcls – 2	Commercial Customers (CUST)
revcls – 1	Residential Usage (USAGE)
revcls – 2	Commercial Usage (USAGE)

Exogenous Variables

bcdd65	Cooling Degree-days
bhdd65	Heating Degree-days
coml	Binary Variable – January 1994
com2	Binary Variable – November 1997 (-1) and December 1997 (1)
ind1	Binary Variable – January 2000 (1) and February 2000 (-1)
ind2	Binary Variable – December 2000 (-1) and January 2001 (1)
ind3	Binary Variable – December 1998 (-1) and February 1999 (1)
muni1	Binary Variable – January 1996 (-1) and February 1996 (1)
muni2	Binary Variable – July 1997 (-1) and August 1997 (1)
muni3	Binary Variable – January 1994 on
or1	Binary Variable – August 1995 (1) and September 1995 (-1)

YEAR	MONTH	revcls	KWH	CUST	USAGE	bcdd65	bhdd55	com1	com2	ind1	ind2	ind3	muni1	muni2	muni3	or1
1991	1	1	2.1827E8	132016	1,653	0.000	442.584	0	0	0	0	0	0	0	0	0
1991	1	2	94103000	20541	4,581	0.000	442.584	0	0	0	0	0	0	0	0	0
1991	1	3	2.4844E8	1828	.	0.000	442.584	0	0	0	0	0	0	0	0	0
1991	1	4	937000	406	.	0.000	442.584	0	0	0	0	0	0	0	0	0
1991	1	5.2	4932600	113	.	0.000	442.584	0	0	0	0	0	0	0	0	0
1991	2	1	1.8226E8	132045	7,380	0.000	533.725	0	0	0	0	0	0	0	0	0
1991	2	2	81882000	20596	3,976	0.000	533.725	0	0	0	0	0	0	0	0	0
1991	2	3	2.3292E8	1823	.	0.000	533.725	0	0	0	0	0	0	0	0	0
1991	2	4	784000	409	.	0.000	533.725	0	0	0	0	0	0	0	0	0
1991	2	5.2	3298800	113	.	0.000	533.725	0	0	0	0	0	0	0	0	0
1991	3	1	1.7604E8	132002	1,334	3.338	410.022	0	0	0	0	0	0	0	0	0
1991	3	2	83085000	20570	4,039	3.338	410.022	0	0	0	0	0	0	0	0	0
1991	3	3	2.375E8	1809	.	3.338	410.022	0	0	0	0	0	0	0	0	0
1991	3	4	782000	411	.	3.338	410.022	0	0	0	0	0	0	0	0	0
1991	3	5.2	3603030	113	.	3.338	410.022	0	0	0	0	0	0	0	0	0
1991	4	1	1.2939E8	131884	981	25.526	183.428	0	0	0	0	0	0	0	0	0
1991	4	2	74112000	20588	3,600	25.526	183.428	0	0	0	0	0	0	0	0	0
1991	4	3	2.1128E8	1791	.	25.526	183.428	0	0	0	0	0	0	0	0	0
1991	4	4	709000	412	.	25.526	183.428	0	0	0	0	0	0	0	0	0
1991	4	5.2	2254800	113	.	25.526	183.428	0	0	0	0	0	0	0	0	0
1991	5	1	1.3273E8	131872	1,007	78.444	35.508	0	0	0	0	0	0	0	0	0
1991	5	2	87717000	20625	4,253	78.444	35.508	0	0	0	0	0	0	0	0	0
1991	5	3	2.3608E8	1786	.	78.444	35.508	0	0	0	0	0	0	0	0	0
1991	5	4	664000	413	.	78.444	35.508	0	0	0	0	0	0	0	0	0
1991	5	5.2	1887700	113	.	78.444	35.508	0	0	0	0	0	0	0	0	0
1991	6	1	1.3725E8	132027	1,040	287.300	0.000	0	0	0	0	0	0	0	0	0
1991	6	2	79367000	20703	3,834	287.300	0.000	0	0	0	0	0	0	0	0	0
1991	6	3	2.2378E8	1787	.	287.300	0.000	0	0	0	0	0	0	0	0	0
1991	6	4	556000	413	.	287.300	0.000	0	0	0	0	0	0	0	0	0
1991	6	5.2	1776800	113	.	287.300	0.000	0	0	0	0	0	0	0	0	0
1991	7	1	1.6721E8	132194	1,265	380.241	0.000	0	0	0	0	0	0	0	0	0
1991	7	2	88459000	20729	4,267	380.241	0.000	0	0	0	0	0	0	0	0	0
1991	7	3	2.2413E8	1773	.	380.241	0.000	0	0	0	0	0	0	0	0	0
1991	7	4	622000	411	.	380.241	0.000	0	0	0	0	0	0	0	0	0
1991	7	5.2	2707200	113	.	380.241	0.000	0	0	0	0	0	0	0	0	0
1991	8	1	1.5646E8	132405	1,182	390.942	0.000	0	0	0	0	0	0	0	0	0

1991	8	2	81871000	20737	3,946	390.942	0 000	0	0	0	0	0	0	0	0	0

YEAR	MONTH	revcls	KWH	CUST	USAGE	bcdd65	bhdd55	com1	com2	ind1	ind2	ind3	muni1	muni2	muni3	or1
991	8	3	2 347[illegible]E8	1770	.	390.942	0.000	0	0	0	0	0	0	0	0	0
991	8	4	680000	412	.	390.942	0.000	0	0	0	0	0	0	0	0	0
1991	8	5.2	2166000	113	.	390.942	0.000	0	0	0	0	0	0	0	0	0
1991	9	1	1 Z24≥E8	132437	925	329.058	0.000	0	0	0	0	0	0	0	0	0
1991	9	2	81498000	20811	3,916	329.058	0.000	0	0	0	0	0	0	0	0	0
1991	9	3	2 265E8	1764	.	329.058	0.000	0	0	0	0	0	0	0	0	0
1991	9	4	715000	412	.	329.058	0.000	0	0	0	0	0	0	0	0	0
<991	9	5.2	1881400	113	.	329.058	0.000	0	0	0	0	0	0	0	0	0
1991	10	1	1 2097E8	132656	912	122.264	31.973	0	0	0	0	0	0	0	0	0
1991	10	2	70753000	20829	3,397	122.264	31.973	0	0	0	0	0	0	0	0	0
1991	10	3	2 4924E8	1751	.	122.264	31.973	0	0	0	0	0	0	0	0	0
1991	10	4	821000	410	.	122.264	31.973	0	0	0	0	0	0	0	0	0
1991	10	5.2	1762000	113	.	122.264	31.973	0	0	0	0	0	0	0	0	0
1991	11	1	1 527E8	132904	1,149	37.144	187.028	0	0	0	0	0	0	0	0	0
1991	11	2	79626000	20854	3,818	37.144	187.028	0	0	0	0	0	0	0	0	0
1991	11	3	2 5859E8	1749	.	37.144	187.028	0	0	0	0	0	0	0	0	0
1991	11	4	885000	410	.	37.144	187.028	0	0	0	0	0	0	0	0	0
1991	11	5.2	1848600	113	.	37.144	187.028	0	0	0	0	0	0	0	0	0
1991	12	1	2 0128E8	133091	1,512	3.600	341.330	0	0	0	0	0	0	0	0	0
1991	12	2	86504000	20850	4,149	3.600	341.330	0	0	0	0	0	0	0	0	0
1991	12	3	2 383<E8	1744	.	3.600	341.330	0	0	0	0	0	0	0	0	0
1991	12	4	940000	408	.	3.600	341.330	0	0	0	0	0	0	0	0	0
1991	12	5.2	2490800	113	.	3.600	341.330	0	0	0	0	0	0	0	0	0
1992	1	1	2 <76E8	133234	1,633	0.000	494.651	0	0	0	0	0	0	0	0	0
1992	1	2	90742000	20872	4,348	0.000	494.651	0	0	0	0	0	0	0	0	0
<992	<	3	2 5418E8	1754		0 000	494 651	0	0	0	0	0	0	0	0	0
<992	1	4	920000	407		0 000	4≥4 651	0	0	0	0	0	0	0	0	0
1992	1	5 2	2382700	113	.	0.000	494.651	0	0	0	0	0	0	0	0	0
<992	2	1	1.8591E8	133373	1,394	0.000	577.120	0	0	0	0	0	0	0	0	0
1992	2	2	81597000	20894	3,905	0.000	577.120	0	0	0	0	0	0	0	0	0
1992	2	3	2.2952E8	1753	.	0.000	577.120	0	0	0	0	0	0	0	0	0
1992	2	4	791000	406	.	0.000	577.120	0	0	0	0	0	0	0	0	0
<992	2	5 2	2149100	113	.	0.000	577.120	0	0	0	0	0	0	0	0	0
1992	3	1	1.7044E8	133446	1,277	0.720	321.040	0	0	0	0	0	0	0	0	0
<992	3	2	85838000	20930	4,101	0.720	321.040	0	0	0	0	0	0	0	0	0

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1992	3	3	2.6065E8	1751	.	0.720	321.040	0	0	0	0	0	0	0	0	0
1992	3	4	822000	405	.	0.720	321.040	0	0	0	0	0	0	0	0	0

YEAR	MONTH	revcls	KWH	CUST	USAGE	bcdd65	bhdd55	coml	com2	ind1	ind2	ind3	muni1	muni2	muni3	or1
1992	3	5.2	2155400	113	.	0.720	321.040	0	0	0	0	0	0	0	0	0
1992	4	1	1.4025E8	133464	1,051	11.847	318.029	0	0	0	0	0	0	0	0	0
1992	4	2	72375000	20981	3,450	11.847	3'8.029	0	0	0	0	0	0	0	0	0
1992	4	3	2.3773E8	1747	.	11.847	318.029	0	0	0	0	0	0	0	0	0
1992	4	4	677000	406	.	11.847	318.029	0	0	0	0	0 .	0	0	0	0
1992	4	5.2	1771700	113	.	11.847	318.029	0	0	0	0	0	0	0	0	0
1992	5	1	1.1686E8	133445	876	53.998	78.607	0	0	0	0	0	0	0	0	0
1992	5	2	79595000	21070	3,778	53.998	78.607	0	0	0	0	0	0	0	0	0
1992	5	3	2.3776E8	1721	.	53.998	78.607	0	0	0	0	0	0	0	0	0
1992	5	4	656000	405	.	53.998	78.607	0	0	0	0	0	0	0	0	0
1992	5	5.2	1629800	113	.	53.998	78.607	0	0	0	0	0	0	0	0	0
1992	6	1	1.1289E8	133566	845	85.480	11.323	0	0	0	0	0	0	0	0	0
1992	6	2	73611000	21150	3,480	85.480	11.323	0	0	0	0	0	0	0	0	0
1992	6	3	2.3661E8	1719	.	85.480	11.323	0	0	0	0	0	0	0	0	0
1992	6	4	580000	405	.	85.480	11.323	0	0	0	0	0	0	0	0	0
1992	6	5.2	1818200	113	.	85.480	11.323	0	0	0	0	0	0	0	0	0
1992	7	1	1.6727E8	133827	1,250	230.750	0.065	0	0	0	0	0	0	0	0	0
1992	7	2	94839000	21186	4,476	230.750	0.065	0	0	0	0	0	0	0	0	0
1992	7	3	2.1677E8	1708	.	230.750	0.065	0	0	0	0	0	0	0	0	0
1992	7	4	634000	405	.	230.750	0.065	0	0	0	0	0	0	0	0	0
1992	7	5.2	2173300	113	.	230.750	0.065	0	0	0	0	0	0	0	0	0
1992	8	1	1.4714E8	133959	1,098	272.802	0.000	0	0	0	0	0	0	0	0	0
1992	8	2	83668000	21243	3,939	272.802	0.000	0	0	0	0	0	0	0	0	0
1992	8	3	2.2098E8	1709	.	272.802	0.000	0	0	0	0	0	0	0	0	0
1992	8	4	652000	408	.	272.802	0.000	0	0	0	0	0	0	0	0	0
1992	8	5.2	1906000	113	.	272.802	0.000	0	0	0	0	0	0	0	0	0
1992	9	1	1.2707E8	134111	947	208.365	0.000	0	0	0	0	0	0	0	0	0
1992	9	2	83425000	21330	3,911	208.365	0.000	0	0	0	0	0	0	0	0	0
1992	9	3	2.1304E8	1709	.	208.365	0.000	0	0	0	0	0	0	0	0	0
1992	9	4	737000	408	.	208.365	0.000	0	0	0	0	0	0	0	0	0
1992	9	5.2	1829900	113	.	208.365	0.000	0	0	0	0	0	0	0	0	0
1992	10	1	1.2874E8	134211	959	67.219	21.403	0	0	0	0	0	0	0	0	0
1992	10	2	79136000	21315	3,713	67.219	21.403	0	0	0	0	0	0	0	0	0
1992	10	3	2.3496E8	1725	.	67.219	21.403	0	0	0	0	0	0	0	0	0

1992	10	4	864000	409	.	67.219	21.403	0	0	0	0	0	0	0	0	0
1992	10	5.2	1689300	113	.	67.219	21.403	0	0	0	0	0	0	0	0	0
1992	11	1	1.5204E8	134592	1,130	3.109	134.798	0	0	0	0	0	0	0	0	0

YEAR	MONTH	revcls	KWH	CUST	USAGE	bcdd65	bhdd55	coml	com2	ind1	ind2	ind3	muni1	muni2	muni3	or1
1992	11	2	77874000	21354	3,647	3.109	134.798	0	0	0	0	0	0	0	0	0
1992	11	3	2.4001E8	1730	.	3.109	134.798	0	0	0	0	0	0	0	0	0
1992	11	4	873000	415		3.109	134.798	0	0	0	0	0	0	0	0	0
1992	11	5.2	1905100	113		3.109	134.798	0	0	0	0	0	0	0	0	0
1992	12	1	2.1983E8	134850	1,630	0.000	394.019	0	0	0	0	0	0	0	0	0
1992	12	2	88659000	21308	4,161	0.000	394.019	0	0	0	0	0	0	0	0	0
1992	12	3	2.3697E8	1755		0.000	394.019	0	0	0	0	0	0	0	0	0
1992	12	4	980000	418		0.000	394.019	0	0	0	0	0	0	0	0	0
1992	12	5.2	2693660	113		0.000	394.319	0	0	0	0	0	0	0	0	0
1993	1	1	2.0928E8	135091	1,549	0.000	473.477	0	0	0	0	0	0	0	0	0
1993	1	2	90173000	21265	4,240	0.000	473.477	0	0	0	0	0	0	0	0	0
1993	1	3	2.3822E8	1782		0.000	473.477	0	0	0	0	0	0	0	0	0
1993	1	4	941000	419		0.000	473.477	0	0	0	0	0	0	0	0	0
1993	1	5.2	2422000	113		0.000	473.477	0	0	0	0	0	0	0	0	0
1993	2	1	2.0668E8	135218	1,529	0.000	509.279	0	0	0	0	0	0	0	0	0
1993	2	2	89794000	21297	4,216	0.000	509.279	0	0	0	0	0	0	0	0	0
1993	2	3	2.3042E8	1799		0.000	509.279	0	0	0	0	0	0	0	0	0
1993	2	4	811000	421		0.000	509.279	0	0	0	0	0	0	0	0	0
1993	2	5.2	3097000	113		0.000	509.279	0	0	0	0	0	0	0	0	0
1993	3	1	2.0632E8	135374	1,524	0.000	613.543	0	0	0	0	0	0	0	0	0
1993	3	2	90203000	21324	4,230	0.000	613.543	0	0	0	0	0	0	0	0	0
1993	3	3	2.279E8	1811		3.000	613.543	0	0	0	0	0	0	0	0	0
1993	3	4	810000	425		0.000	613.543	0	0	0	0	0	0	0	0	0
1993	3	5.2	2500000	113		0.000	613.543	0	0	0	0	0	0	0	0	0
1993	4	1	1.394E8	135338	1,030	0.818	278.660	0	0	0	0	0	0	0	0	0
1993	4	2	73121000	21329	3,428	0.818	278.660	0	0	0	0	0	0	0	0	0
1993	4	3	2.2261E8	1812	.	0.818	278.660	0	0	0	0	0	0	0	0	0
1993	4	4	716000	424	.	0.818	278.660	0	0	0	0	0	0	0	0	0
1993	4	5.2	2880000	113		0.818	278.660	0	3	0	0	0	0	0	0	0
1993	5	1	1.0582E8	135216	783	44.082	53.376	0	0	0	0	0	0	0	0	0
1993	5	2	82710000	21386	3,867	44.082	53.376	0	0	0	0	0	0	0	0	0
1993	5	3	2.3372E8	1803		44.082	53.376	3	0	0	0	0	0	0	0	0
1993	5	4	678000	425		44.082	53.376	0	0	0	0	0	0	0	0	0

1993	5	5.2	1735000	113	.	44.082	53.376	0	0	0	0	0	0	0	0	0
1993	6	1	1.3905E8	135294	1,028	108.617	5.007	0	0	0	0	0	0	0	0	0
1993	6	2	89091000	21427	4,158	108.617	5.007	0	0	0	0	0	0	0	0	0
1993	6	3	2.2668E8	1807	.	108.617	5.007	0	0	0	0	0	0	0	0	0

YEAR	MONTH	revcls	KWH	CUST	USAGE	bcdd65	bhdd55	com1	com2	ind1	ind2	ind3	muni1	muni2	muni3	or1
1993	6	4	628000	425	.	108.617	5.007	0	0	0	0	0	0	0	0	0
1993	6	5.2	1859000	113	.	108.617	5.007	0	0	0	0	0	0	0	0	0
1993	7	1	2.0039E8	135439	1,480	351.999	0.000	0	0	0	0	0	0	0	0	0
1993	7	2	1.015E8	21507	4,719	351.999	0.000	0	0	0	0	0	0	0	0	0
1993	7	3	2.0969E8	1813	.	351.999	0.000	0	0	0	0	0	0	0	0	0
1993	7	4	625000	430	.	351.999	0.000	0	0	0	0	0	0	0	0	0
1993	7	5.2	2556000	113	.	351.999	0.000	0	0	0	0	0	0	0	0	0
1993	8	1	1.6459E8	135778	1,212	374.285	0.000	0	0	0	0	0	0	0	0	0
1993	8	2	90728000	21535	4,213	374.285	0.000	0	0	0	0	0	0	0	0	0
1993	8	3	2.4356E8	1810	.	374.285	0.000	0	0	0	0	0	0	0	0	0
1993	8	4	688000	447	.	374.285	0.000	0	0	0	0	0	0	0	0	0
1993	8	5.2	2127000	113	.	374.285	0.000	0	0	0	0	0	0	0	0	0
1993	9	1	1.168E8	136030	859	330.400	0.000	0	0	0	0	0	0	0	0	0
1993	9	2	80456000	21626	3,720	330.400	0.000	0	0	0	0	0	0	0	0	0
1993	9	3	2.1444E8	1815	.	330.400	0.000	0	0	0	0	0	0	0	0	0
1993	9	4	739000	447	.	330.400	0.000	0	0	0	0	0	0	0	0	0
1993	9	5.2	1761000	113	.	330.400	0.000	0	0	0	0	0	0	0	0	0
1993	10	1	1.0994E8	136227	807	60.575	24.184	0	0	0	0	0	0	0	0	0
1993	10	2	78145000	21700	3,601	60.575	24.184	0	0	0	0	0	0	0	0	0
1993	10	3	2.5069E8	1816	.	60.575	24.184	0	0	0	0	0	0	0	0	0
1993	10	4	890000	454	.	60.575	24.184	0	0	0	0	0	0	0	0	0
1993	10	5.2	1785000	113	.	60.575	24.184	0	0	0	0	0	0	0	0	0
1993	11	1	1.6327E8	136537	1,196	8.934	173.381	0	0	0	0	0	0	0	0	0
1993	11	2	78256000	21756	3,597	8.934	173.381	0	0	0	0	0	0	0	0	0
1993	11	3	2.3507E8	1829	.	8.934	173.381	0	0	0	0	0	0	0	0	0
1993	11	4	927000	457	.	8.934	173.381	0	0	0	0	0	0	0	0	0
1993	11	5.2	2022000	113	.	8.934	173.381	0	0	0	0	0	0	0	0	0
1993	12	1	2.1002E8	136822	1,535	4.123	310.797	0	0	0	0	0	0	0	0	0
1993	12	2	90211000	21794	4,139	4.123	310.797	0	0	0	0	0	0	0	0	0
1993	12	3	2.5325E8	1827	.	4.123	310.797	0	0	0	0	0	0	0	0	0
1993	12	4	967000	458	.	4.123	310.797	0	0	0	0	0	0	0	0	0
1993	12	5.2	3024000	113	.	4.123	310 797	0	0	0	0	0	0	0	0	0

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1994	1	1	2.7613E8	137060	2,015	0.000	739.800	1	0	0	0	0	0	0	1	0
1994	1	2	1.2016E8	21834	5,503	0.000	739.800	1	0	0	0	0	0	0	1	0
1994	1	3	2.4051E8	1825	.	0.000	739.800	1	0	0	0	0	0	0	1	0
1994	1	4	958000	459	.	0.000	739.800	1	0	0	0	0	0	0	1	0
1994	1	5 2	8318000	113	.	0.000	739.800	1	0	0	0	0	0	0	1	0

YEAR	MONTH	revcls	KWH	CUST	USAGE	bcdd65	bhdd55	com1	com2	ind1	ind2	ind3	muni1	muni2	muni3	or1
1994	2	1	2.1248E8	137115	1,550	0.000	790.099	0	0	0	0	0	0	0	1	0
1994	2	2	82840000	21843	3,793	0.000	790.099	0	0	0	0	0	0	0	1	0
1994	2	3	2.1718E8	1823	.	0.000	790.099	0	0	0	0	0	0	0	1	0
1994	2	4	781000	459	.	0.000	790.099	0	0	0	0	0	0	0	1	0
1994	2	5.2	6602000	113	.	0.000	790.099	0	0	0	0	0	0	0	1	0
1994	3	1	1.9066E8	136980	1,392	0.098	447.231	0	0	0	0	0	0	0	1	0
1994	3	2	83707000	21862	3,829	0.098	447.231	0	0	0	0	0	0	0	1	0
1994	3	3	2.3805E8	1818	.	0.098	447.231	0	0	0	0	0	0	0	1	0
1994	3	4	862000	456	.	0.098	447.231	0	0	0	0	0	0	0	1	0
1994	3	5.2	6490000	113	.	0.098	447.231	0	0	0	0	0	0	0	1	0
1994	4	1	1.3338E8	136897	974	6.349	234.448	0	0	0	0	0	0	0	1	0
1994	4	2	75239000	21894	3,437	6.349	234.448	0	0	0	0	0	0	0	1	0
1994	4	3	2.3384E8	1805	.	6.349	234.448	0	0	0	0	0	0	0	1	0
1994	4	4	728000	456	.	6.349	234.448	0	0	0	0	0	0	0	1	0
1994	4	5.2	5052000	113	.	6.349	234.448	0	0	0	0	0	0	0	1	0
1994	5	1	1.1516E8	136933	841	46.798	30.893	0	0	0	0	0	0	0	1	0
1994	5	2	81085000	22030	3,681	46.798	30.893	0	0	0	0	0	0	0	1	0
1994	5	3	2.4532E8	1807	.	46.798	30.893	0	0	0	0	0	0	0	1	0
1994	5	4	693000	456	.	46.798	30.893	0	0	0	0	0	0	0	1	0
1994	5	5.2	4988000	113	.	46.798	30.893	0	0	0	0	0	0	0	1	0
1994	6	1	1.4983E8	137070	1,093	132.343	3.894	0	0	0	0	0	0	0	1	0
1994	6	2	94673000	22079	4,288	132.343	3.894	0	0	0	0	0	0	0	1	0
1994	6	3	2.3716E8	1797	.	132.343	3.894	0	0	0	0	0	0	0	1	0
1994	6	4	624000	457	.	132.343	3.894	0	0	0	0	0	0	0	1	0
1994	6	5.2	6346000	113	.	132.343	3.894	0	0	0	0	0	0	0	1	0
1994	7	1	1.7871E8	137264	1,302	371.176	0.000	0	0	0	0	0	0	0	1	0
1994	7	2	97737000	22161	4,410	371.176	0.000	0	0	0	0	0	0	0	1	0
1994	7	3	2.243E8	1797	.	371.176	0.000	0	0	0	0	0	0	0	1	0
1994	7	4	663000	457	.	371.176	0.000	0	0	0	0	0	0	0	1	0
1994	7	5.2	6877000	113	.	371.176	0.000	0	0	0	0	0	0	0	1	0
1994	8	1	1.5619E8	137444	1,136	305.921	0.000	0	0	0	0	0	0	0	1	0

1994	8	2	93208000	22211	4,1[illegible]	30[illegible] [illegible]21	0.000	0	0	0	0	0	0	0	1	0
1994	8	3	2.4344≤≤	1795	.	30[illegible] [illegible]21	0.000	0	0	0	0	0	0	0	1	0
1994	8	4	6950oo	458	.	30[illegible] [illegible]21	0.000	0	0	0	0	0	0	0	1	0
1994	8	5.2	62010oo	113		30[illegible] [illegible]21	0.000	0	0	0	0	0	0	0	1	0
1994	9	1	1.1257≤≤	137657	818	176.948	0.000	0	0	0	0	0	0	0	1	0
1994	9	2	820380oo	22267	3,684	176 [illegible]48	0.000	0	0	0	0	0	0	0	1	0

YEAR	MONTH	r[illegible]vols	KWH	CWST	USAGE	[illegible]odd6[illegible]	[illegible]hdd[illegible]5	c[illegible]m1	c[illegible]m2	ind1	ind2	ind3	muni1	muni2	muni3	[illegible]r1
1994	9	3	2.3366≤8	1797	.	176 [illegible]48	0 000	0	0	0	0	0	0	0	1	0
1994	9	4	767000	460	.	176.948	0 000	0	0	0	0	0	0	0	1	0
1994	9	[illegible] 2	5050[illegible]0	113	.	176 948	0 000	0	0	0	0	0	0	0	1	0
1994	10	1	1.2851≤8	137923	[illegible]32	43 [illegible]2[illegible]	[illegible] [illegible]16	0	0	0	0	0	0	0	1	0
1994	10	2	84321[illegible]o0	22326	3,777	43.[illegible]25	[illegible] [illegible]16	0	0	0	0	0	0	0	1	0
1994	10	3	2.501[illegible]≤8	1793	.	43.525	9.916	0	0	0	0	0	0	0	1	0
1994	10	4	899≤o0	460	.	43.525	9.916	0	0	0	0	0	0	0	1	0
1994	10	[illegible] 2	[illegible]018[illegible]0	113	.	43.[illegible]25	[illegible] [illegible]16	0	0	0	0	0	0	0	1	0
1994	11	1	1.[illegible]86[illegible]≤8	138233	1,148	4 483	[illegible]4 288	0	0	0	0	0	0	0	1	0
1994	11	2	83[illegible]000o0	22360	3,716	4 483	[illegible]4.288	0	0	0	0	0	0	0	1	0
1994	11	3	2.454≤8	1786	.	4.483	74.288	0	0	0	0	0	0	0	1	0
1994	11	4	9510o0	460	.	4.483	74.288	0	0	0	0	0	0	0	1	0
1994	11	[illegible] 2	[illegible]5560o0	113	.	4.483	74.288	0	0	0	0	0	0	0	1	0
1994	12	1	2 12[illegible]4≤8	138639	1,533	1.800	254.149	0	0	0	0	0	0	0	1	0
1994	12	2	[illegible]4267000	22402	4,208	1.800	254.149	0	0	0	0	0	0	0	1	0
1994	12	3	2.6086≤8	1784	.	1.800	254.149	0	0	0	0	0	0	0	1	0
1994	12	4	1015000	461	.	1.800	254.149	0	0	0	0	0	0	0	1	0
1994	12	[illegible] 2	6896000	113	.	1.800	254.149	0	0	0	0	0	0	0	1	0
1995	1	1	2 5[illegible]1≤8	138751	1,844	0.000	508.821	0	0	0	0	0	0	0	1	0
1995	1	2	1 03[illegible]3≤8	22429	4,616	0 000	[illegible]08 821	0	0	0	0	0	0	0	1	0
1995	1	3	2 6223≤8	1783	.	0.000	[illegible]08.821	0	0	0	0	0	0	0	1	0
1995	1	4	[illegible]88000	462	.	0.000	508.821	0	0	0	0	0	0	0	1	0
1995	1	[illegible] 2	7826000	113	.	0.000	508.821	0	0	0	0	0	0	0	1	0
1995	2	1	2 2202≤8	139081	1,596	0.000	683.904	0	0	0	0	0	0	0	1	0
1995	2	2	[illegible]75[illegible]000	22470	4,261	0.000	683.904	0	0	0	0	0	0	0	1	0
1995	2	3	2 [illegible]1[illegible]6≤8	1778	.	0.000	683.904	0	0	0	0	0	0	0	1	0
1995	2	4	828000	463	.	0.000	683.904	0	0	0	0	0	0	0	1	0
1995	2	[illegible] 2	7425000	113	.	0.000	683.904	0	0	0	0	0	0	0	1	0
1995	3	1	1 [illegible]445E8	139035	1,2[illegible]	0 000	467 717	0	0	0	0	0	0	0	1	0
1995	3	2	857[illegible]1000	22477	3,81[illegible]	0 000	467 717	0	0	0	0	0	0	0	1	0

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YEAR	MONTH	revcls	KWH	CUST	USAGE	bcdd65	bhdd55	com1	com2	ind1	ind2	ind3	muni1	muni2	muni3	or1
1995	3	3	2.5988E8	1770	.	0.000	467.717	0	0	0	0	0	0	0	1	0
1995	3	4	769000	463	.	0.000	467.717	0	0	0	0	0	0	0	1	0
1995	3	5.2	617400	113	.	0.000	467.717	0	0	0	0	0	0	0	1	0
1995	4	1	1.3453E8	138956	968	6.349	172.760	0	0	0	0	0	0	0	1	0
1995	4	2	7777000	22554	3,448	6.349	172.760	0	0	0	0	0	0	0	1	0
1995	4	3	2.3647E8	1757	.	6.349	172.760	0	0	0	0	0	0	0	1	0
1995	4	4	751000	465	.	6.349	172.760	0	0	0	0	0	0	0	1	0

YEAR	MONTH	revcls	KWH	CUST	USAGE	bcdd65	bhdd55	com1	com2	ind1	ind2	ind3	muni1	muni2	muni3	or1
1995	4	5.2	534200	113	.	6.349	172.760	0	0	0	0	0	0	0	1	0
1995	5	1	1.2587E8	139003	906	25.788	61.917	0	0	0	0	0	0	0	1	0
1995	5	2	8486400	22642	3,748	25.788	61.917	0	0	0	0	0	0	0	1	0
1995	5	3	2.4798E8	1761	.	25.788	61.917	0	0	0	0	0	0	0	1	0
1995	5	4	694000	464	.	25.788	61.917	0	0	0	0	0	0	0	1	0
1995	5	5.2	532700	113	.	25.788	61.917	0	0	0	0	0	0	0	1	0
1995	6	1	1.3363E8	139129	960	116.046	3.960	0	0	0	0	0	0	0	1	0
1995	6	2	9244100	22685	4,075	116.046	3.960	0	0	0	0	0	0	0	1	0
1995	6	3	2.4551E8	1747	.	116.046	3.960	0	0	0	0	0	0	0	1	0
1995	6	4	651000	463	.	116.046	3.960	0	0	0	0	0	0	0	1	0
1995	6	5.2	605200	113	.	116.046	3.960	0	0	0	0	0	0	0	1	0
1995	7	1	1.9213E8	139232	1,380	274.504	0.000	0	0	0	0	0	0	0	1	0
1995	7	2	1.0533E8	22706	4,639	274.504	0.000	0	0	0	0	0	0	0	1	0
1995	7	3	2.342E8	1750	.	274.504	0.000	0	0	0	0	0	0	0	1	0
1995	7	4	815000	462	.	274.504	0.000	0	0	0	0	0	0	0	1	0
1995	7	5.2	713800	113	.	274.504	0.000	0	0	0	0	0	0	0	1	0
1995	8	1	2.1394E8	139483	1,534	428.054	0.000	0	0	0	0	0	0	0	1	1
1995	8	2	1.1088E8	22754	4,873	428.054	0.000	0	0	0	0	0	0	0	1	1
1995	8	3	2.5312E8	1750	.	428.054	0.000	0	0	0	0	0	0	0	1	1
1995	8	4	871000	462	.	428.054	0.000	0	0	0	0	0	0	0	1	1
1995	8	5.2	816900	113	.	428.054	0.000	0	0	0	0	0	0	0	1	1
1995	9	1	1.2798E8	139721	916	337.469	0.491	0	0	0	0	0	0	0	1	-1
1995	9	2	8656600	22811	3,795	337.469	0.491	0	0	0	0	0	0	0	1	-1
1995	9	3	2.3316E8	1749	.	337.469	0.491	0	0	0	0	0	0	0	1	-1
1995	9	4	770000	465	.	337.469	0.491	0	0	0	0	0	0	0	1	-1
1995	9	5.2	543500	113	.	337.469	0.491	0	0	0	0	0	0	0	1	-1
1995	10	1	1.253E8	139866	896	62.735	13.123	0	0	0	0	0	0	0	1	0
1995	10	2	8906300	22821	3,903	62.735	13.123	0	0	0	0	0	0	0	1	0
1995	10	3	2.6248E8	1755	.	62.735	13.123	0	0	0	0	0	0	0	1	0

1995	10	4	928000	466	.	62.735	13.123	0	0	0	0	0	0	0	1	0
1995	10	5.2	5544000	113	.	62.735	13.123	0	0	0	0	0	0	0	1	0
1995	11	1	2.0991E8	140041	1,499	5.792	196.813	0	0	0	0	0	0	0	1	0
1995	11	2	96800000	22767	4,252	5.792	196.813	0	0	0	0	0	0	0	1	0
1995	11	3	2.4704E8	1727	.	5.792	196.813	0	0	0	0	0	0	0	1	0
1995	11	4	993000	466	.	5.792	196.813	0	0	0	0	0	0	0	1	0
1995	11	5.2	6609000	113	.	5.792	196.813	0	0	0	0	0	0	0	1	0
1995	12	1	2.7631E8	140410	1,968	0.393	481.135	0	0	0	0	0	0	0	1	0

YEAR	MONTH	revcls	KWH	CUST	USAGE	bcdd65	bhdd55	com1	com2	ind1	ind2	ind3	muni1	muni2	muni3	or1
1995	12	2	1.0576E8	22796	4,639	0.393	481.135	0	0	0	0	0	0	0	1	0
1995	12	3	2.462E8	1712		0.393	481.135	0	0	0	0	0	0	0	1	0
1995	12	4	1024000	466	.	0.393	481.135	0	0	0	0	0	0	0	1	0
1995	12	5.2	7244000	113		0.393	481.135	0	0	0	0	0	0	0	I	0
1996	I	1	2.9241E8	140797	2,077	0.000	730.931	0	0	0	0	0	-1	0	1	0
1996	1	2	1.1321E8	22844	4,956	0.000	730.931	0	0	0	0	0	-1	0	1	0
1996	1	3	2.2667E8	1711		0.000	730.931	0	0	0	0	0	-1	0	1	0
1996	1	4	1019312	418		0.000	730.931	0	0	0	0	0	-1	0	1	0
1996	1	5.2	-5360218	113		0.000	730.931	0	0	0	0	0	-1	0	1	0
1996	2	1	2.7509E8	140265	1,961	0.000	726.807	0	0	0	0	0	1	0	1	0
1996	2	2	1.0917E8	22698	4,810	0.000	726.807	0	0	0	0	0	1	0	1	0
1996	2	3	2.6242E8	1713		0.000	726.807	0	0	0	0	0	1	0	1	0
1996	2	4	863441	383		0.000	726.807	0	0	0	0	0	1	0	1	0
1996	2	5.2	22686123	113		0.000	726.807	0	0	0	0	0	1	0	1	0
1996	3	1	2.1707E8	140887	1,541	0.000	501.065	0	0	0	0	0	0	0	1	0
1996	3	2	95628277	22936	4,169	0.000	501.065	0	0	0	0	0	0	0	1	0
1996	3	3	2.8379E8	1716		0.000	501.065	0	0	0	0	0	0	0	1	0
1996	3	4	863231	484		0.000	501.065	0	0	0	0	0	0	0	[illegible]	0
1996	3	5.2	7255821	113		0.000	501.065	0	0	0	0	0	0	0	1	0
1996	4	1	1.9012E8	140586	1,352	7.134	345.650	0	0	0	0	0	0	0	1	0
1996	4	2	91701166	22959	3,994	7.134	345.650	0	0	0	0	0	0	0	1	0
1996	4	3	2.6512E8	1735		7.134	345.650	0	0	0	0	0	0	0	1	0
1996	4	4	759216	478	.	7.134	345.650	0	0	0	0	0	0	0	1	0
1996	4	5.2	4035719	113		7.134	345.650	0	0	0	0	0	0	0	1	0
1996	5	1	1.3492E8	140510	960	71,473	75.793	0	0	0	0	0	0	0	1	0
1996	5	2	98296369	22986	4,276	71.473	75.793	0	0	0	0	0	0	0	1	0
1996	5	3	2.5073E8	1712		71.473	75.793	0	0	0	0	0	0	0	1	0
1996	5	4	702386	478		71.473	75.793	0	0	0	0	0	0	0	1	0

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1996	5	5.2	7661217	113	.	71.473	75.793	0	0	0	0	0	0	0	1	0
1996	6	1	1.3907E8	140617	989	153.648	10.407	0	0	0	0	0	0	0	1	0
1996	6	2	85395121	23060	3,703	153.648	10.407	0	0	0	0	0	0	0	1	0
1996	6	3	2.501E8	1737	.	153.648	10.407	0	0	0	0	0	0	0	1	0
1996	6	4	647610	489	.	153.648	10.407	0	0	0	0	0	0	0	1	0
1996	6	5.2	6196037	113	.	153.648	10.407	0	0	0	0	0	0	0	1	0
1996	7	1	1.6749E8	140661	1,191	293.943	0.000	0	0	0	0	0	0	0	1	0
1996	7	2	98462362	22905	4,299	293.943	0.000	0	0	0	0	0	0	0	1	0
1996	7	3	2.3444E8	1719	.	293.943	0.000	0	0	0	0	0	0	0	1	0

YEAR	MONTH	revcls	KWH	CUST	USAGE	bcdd65	bhdd65	com1	com2	ind1	ind2	ind3	muni1	muni2	muni3	or1
1996	7	4	[illegible]	484	.	293.943	0.000	0	0	0	0	0	0	0	1	0
1996	7	5 2	44[illegible]746	113	.	293.943	0.000	0	0	0	0	0	0	0	1	0
1996	8	1	[illegible]	140725	1,142	269.955	0.000	0	0	0	0	0	0	0	1	0
1996	8	2	[illegible]	23044	4,221	269.955	0.000	0	0	0	0	0	0	0	1	0
1996	8	3	[illegible]	1683	.	269.955	0.000	0	0	0	0	0	0	0	1	0
1996	8	4	[illegible]	486	.	269.955	0.000	0	0	0	0	0	0	0	1	0
1996	8	5 2	9341771	113	.	269.955	0.000	0	0	0	0	0	0	0	1	0
1996	9	1	[illegible]	140996	1,113	233.859	0.000	0	0	0	0	0	0	0	1	0
1996	9	2	[illegible]	23204	4,243	233.859	0.000	0	0	0	0	0	0	0	1	0
1996	9	3	[illegible]	1694	.	233.859	0.000	0	0	0	0	0	0	0	1	0
1996	9	4	[illegible]	485	.	233.859	0.000	0	0	0	0	0	0	0	1	0
1996	9	5 2	4474171	113	.	233.859	0.000	0	0	0	0	0	0	0	1	0
1996	10	1	1.2403E8	141077	879	42.871	23.072	0	0	0	0	0	0	0	1	0
1996	10	2	8269[illegible]9[illegible]7	23343	3,543	42.871	23.072	0	0	0	0	0	0	0	1	0
1996	10	3	2.4[illegible]41E8	1711	.	42.871	23.072	0	0	0	0	0	0	0	1	0
1996	10	4	[illegible]	479	.	42.871	23.072	0	0	0	0	0	0	0	1	0
1996	10	5 2	6711[illegible]04	113	.	42.871	23.072	0	0	0	0	0	0	0	1	0
1996	11	1	[illegible]	141356	1,0[illegible]0	6.054	187.290	0	0	0	0	0	0	0	1	0
1996	11	2	87310544	23309	3,746	6.054	187.290	0	0	0	0	0	0	0	1	0
1996	11	3	[illegible]	1698	.	6.054	187.290	0	0	0	0	0	0	0	1	0
1996	11	4	951012	471	.	6.054	187.290	0	0	0	0	0	0	0	1	0
1996	11	5 2	6987[illegible]74	113	.	6.054	187.290	0	0	0	0	0	0	0	1	0
1996	12	1	[illegible]	141651	1,640	1.440	469.386	0	0	0	0	0	0	0	1	0
1996	12	2	[illegible]	23290	4,514	1.440	469.386	0	0	0	0	0	0	0	1	0
1996	12	3	[illegible]	1703	.	1.440	469.386	0	0	0	0	0	0	0	1	0
1996	12	4	103[illegible]920	470	.	1.440	469.386	0	0	0	0	0	0	0	1	0
1996	12	5 2	[illegible]314221	113	.	1.440	469.386	0	0	0	0	0	0	0	1	0

1997	1	1	2.6563E8	141830	1,870	0.753	511.799	0	0	0	0	0	0	0	1	0
1997	1	2	1.1347E8	23383	4,853	0.753	511.799	0	0	0	0	0	0	0	1	0
1997	1	3	2.7973E8	1689	.	0.753	511.799	0	0	0	0	0	0	0	1	0
1997	1	4	1037584	474	.	0.753	511.799	0	0	0	0	0	0	0	1	0
1997	1	5.2	8483085	113	.	0.753	511.799	0	0	0	0	0	0	0	1	0
1997	2	1	2.4077E8	141839	1,698	0.622	618.289	0	0	0	0	0	0	0	1	0
1997	2	2	1.0245E8	23396	4,379	0.622	618.289	0	0	0	0	0	0	0	1	0
1997	2	3	2.5854E8	1725	.	0.622	618.289	0	0	0	0	0	0	0	1	0
1997	2	4	887651	485	.	0.622	618.289	0	0	0	0	0	0	0	1	0
1997	2	5.2	7017371	113	.	0.622	618.289	0	0	0	0	0	0	0	1	0

YEAR	MONTH	revols	KWH	CUST	USAGE	bcdd65	bhdd55	com1	com2	ind1	ind2	ind3	muni1	muni2	muni3	or1
1997	3	1	1.856E8	141572	1,311	2.651	340.839	0	0	0	0	0	0	0	1	0
1997	3	2	80988450	23484	3,874	2.651	340.839	0	0	0	0	0	0	0	1	0
1997	3	3	2.4512E8	1688	.	2.651	340.839	0	0	0	0	0	0	0	1	0
1997	3	4	886516	481	.	2.651	340.839	0	0	0	0	0	0	0	1	0
1997	3	5.2	6594203	113	.	2.651	340.839	0	0	0	0	0	0	0	1	0
1997	4	1	1.6701E8	141364	1,181	6.054	217.561	0	0	0	0	0	0	0	1	0
1997	4	2	84898022	23487	3,615	6.054	217.561	0	0	0	0	0	0	0	1	0
1997	4	3	2.8425E8	1695	.	6.054	217.561	0	0	0	0	0	0	0	1	0
1997	4	4	790949	481	.	6.054	217.561	0	0	0	0	0	0	0	1	0
1997	4	5.2	5057414	113	.	6.054	217.561	0	0	0	0	0	0	0	1	0
1997	5	1	1.3738E8	141345	972	6.971	100.174	0	0	0	0	0	0	0	1	0
1997	5	2	80429332	23490	3,424	6.971	100.174	0	0	0	0	0	0	0	1	0
1997	5	3	2.529E8	1663	.	6.971	100.174	0	0	0	0	0	0	0	1	0
1997	5	4	716182	480	.	6.971	100.174	0	0	0	0	0	0	0	1	0
1997	5	5.2	5468845	113	.	6.971	100.174	0	0	0	0	0	0	0	1	0
1997	6	1	1.2707E8	141476	898	51.380	15.119	0	0	0	0	0	0	0	1	0
1997	6	2	83911029	23605	3,555	51.380	15.119	0	0	0	0	0	0	0	1	0
1997	6	3	2.4522E8	1686	.	51.380	15.119	0	0	0	0	0	0	0	1	0
1997	6	4	664411	481	.	51.380	15.119	0	0	0	0	0	0	0	1	0
1997	6	5.2	5843017	113	.	51.380	15.119	0	0	0	0	0	0	0	1	0
1997	7	1	1.6605E8	141515	1,173	241.156	0.000	0	0	0	0	0	0	-1	1	0
1997	7	2	1.0238E8	23578	4,342	241.156	0.000	0	0	0	0	0	0	-1	1	0
1997	7	3	2.4814E8	1638	.	241.156	0.000	0	0	0	0	0	0	-1	1	0
1997	7	4	687250	455	.	241.156	0.000	0	0	0	0	0	0	-1	1	0
1997	7	5.2	-7154573	113	.	241.156	0.000	0	0	0	0	0	0	-1	1	0
1997	8	1	1.7206E8	141811	1,213	296.856	0.000	0	0	0	0	0	0	1	1	0

1997	8	2	1 007[illegible]	23747	4,24[illegible]	296.856	0.000	0	0	0	0	0	0	1	1	0
1997	8	3	2 412[illegible]	1692	.	296.856	0.000	0	0	0	0	0	0	1	1	0
1997	8	4	7[illegible]7[illegible]92	460	.	296.856	0.000	0	0	0	0	0	0	1	1	0
1997	8	5.2	21246519	113	.	296.856	0.000	0	0	0	0	0	0	1	1	0
1997	9	1	1.4975E8	141920	1,055	161.109	0.000	0	0	0	0	0	0	0	1	0
1997	9	2	9[illegible]072327	23781	4,124	161.109	0.000	0	0	0	0	0	0	0	1	0
1997	9	3	2 [illegible]0[illegible]2E[illegible]	1673	.	161.109	0.000	0	0	0	0	0	0	0	1	0
1997	9	4	823230	478	.	161.109	0.000	0	0	0	0	0	0	0	1	0
1997	9	5.2	[illegible]94[illegible]10	113	.	161.109	0.000	0	0	0	0	0	0	0	1	0
1997	10	1	1.2228E8	141988	861	50.660	16.0[illegible]6	0	0	0	0	0	0	0	1	0
1997	10	2	86935310	23785	3,655	50.660	16.0[illegible]6	0	0	0	0	0	0	0	1	0

YEAR	MONTH	revcls	KWH	CUST	USAGE	bcdd65	bhdd55	com1	com2	ind1	ind2	ind3	muni1	muni2	muni3	or1
1997	10	3	2.6122E8	1670	.	50.6595	16.036	0	0	0	0	0	0	0	1	0
1997	10	4	924849	478	.	50.6595	16.036	0	0	0	0	0	0	0	1	0
1997	10	5.2	5686998	113	.	50.6595	16.036	0	0	0	0	0	0	0	1	0
1997	11	1	1.679E8	151125	1,111	14.7266	223.746	0	-1	0	0	0	0	0	1	0
1997	11	2	76773356	24985	3,073	14.7266	223.746	0	-1	0	0	0	0	0	1	0
1997	11	3	2.5672E8	1788	.	14.7266	223.746	0	-1	0	0	0	0	0	1	0
1997	11	4	980818	484	.	14.7266	223.746	0	-1	0	0	0	0	0	1	0
1997	11	5.2	6396912	113	.	14.7266	223.746	0	-1	0	0	0	0	0	1	0
1997	12	1	2 422[illegible]	138582	[illegible],748	0.0000	429.068	0	1	0	0	0	0	0	1	0
1997	12	2	1 17[illegible]4[illegible]	23559	[illegible],993	0.0000	429.068	0	1	0	0	0	0	0	1	0
1997	12	3	2 [illegible]201[illegible]	1677	.	0.0000	429.068	0	1	0	0	0	0	0	1	0
1997	12	4	1079438	474	.	0.0000	429.068	0	1	0	0	0	0	0	1	0
1997	12	5.2	8458938	113	.	0.0000	429.068	0	1	0	0	0	0	0	1	0
1998	1	1	2 [illegible]922[illegible]	142740	1,[illegible]1[illegible]	0.0000	458.129	0	0	0	0	0	0	0	1	0
1998	1	2	1.0745E8	24122	4,[illegible]5[illegible]	0.0000	458.129	0	0	0	0	0	0	0	1	0
1998	1	3	2 [illegible]307[illegible]	1[illegible]2[illegible]		0.0000	4[illegible]8.129	0	0	0	0	0	0	0	1	0
1998	1	4	10[illegible]Z831	601	.	0.0000	458.[illegible]9	0	0	0	0	0	0	0	1	0
1998	1	[illegible] 2	7[illegible]10956	113	.	0.0000	458.129	0	0	0	0	0	0	0	1	0
1998	2	1	2.2135E8	142471	1,[illegible]54	0.0000	485.226	0	0	0	0	0	0	0	1	0
1998	2	2	99409464	24003	4,[illegible]42	0.0000	485.226	0	0	0	0	0	0	0	1	0
1998	2	3	2.5712E8	1662	.	0.0000	485.226	0	0	0	0	0	0	0	1	0
1998	2	4	906[illegible]5	475	.	0.0000	485.226	0	0	0	0	0	0	0	1	0
1998	2	5 2	[illegible]241327	113	.	0.0000	485.226	0	0	0	0	0	0	0	1	0
1998	3	1	1.9871E8	142614	1,[illegible]93	0.0327	389.175	0	0	0	0	0	0	0	1	0
1998	3	2	[illegible]1[illegible]0544	23841	3,[illegible]72	0.0327	389.175	0	0	0	0	0	0	0	1	0

1998	3	3	2.7046E8	1615	,	0.0327	389.175	0	0	0	0	0	0	0	1	0
1998	3	4	901367	480	.	0.0327	389.175	0	0	0	0	0	0	0	1	0
1998	3	5.2	9620215	113	.	0.0327	389.175	0	0	0	0	0	0	0	1	0
1998	4	1	1.6549E8	142771	1,159	41.5290	227.248	0	0	0	0	0	0	0	1	0
1998	4	2	95019595	24158	3,933	41.5290	227.248	0	0	0	0	0	0	0	1	0
1998	4	3	2.7134E8	1745	.	41.5290	227.248	0	0	0	0	0	0	0	1	0
1998	4	4	801290	477	.	41.5290	227.248	0	0	0	0	0	0	0	1	0
1998	4	5.2	3646607	113	.	41.5290	227.248	0	0	0	0	0	0	0	1	0
1998	5	1	1.319E8	142280	927	23.2353	33.969	0	0	0	0	0	0	0	1	0
1998	5	2	87043618	24055	3,619	23.2353	33.969	0	0	0	0	0	0	0	1	0
1998	5	3	2.5814E8	1627	.	23.2353	33.969	0	0	0	0	0 .	0	0	1	0
1998	5	4	738492	478	.	23.2353	33.969	0	0	0	0	0	0	0	1	0

YEAR	MONTH	revcls	KWH	CUST	USAGE	bcdd65	bhdd55	com1	com2	ind1	ind2	ind3	muni1	muni2	muni3	or1
1998	5	5.2	5762428	113	.	23.235	33.969	0	0	0	0	0	0	0	1	0
1998	6	1	1.4278E8	142257	1,004	133.456	0.753	0	0	0	0	0	0	0	1	0
1998	6	2	93873460	24137	3,889	133.456	0.753	0	0	0	0	0	0	0	1	0
1998	6	3	2.4512E8	1637	.	133.456	0.753	0	0	0	0	0	0	0	1	0
1998	6	4	679396	478	.	133.456	0.753	0	0	0	0	0	0	0	1	0
1998	6	5.2	6832579	113	.	133.456	0.753	0	0	0	0	0	0	0	1	0
1998	7	1	1.771E8	142397	1,244	285.958	0.327	0	0	0	0	0	0	0	1	0
1998	7	2	1.0913E8	24307	4,490	285.958	0.327	0	0	0	0	0	0	0	1	0
1998	7	3	2.49E8	1676	.	285.958	0.327	0	0	0	0	0	0	0	1	0
1998	7	4	715592	475	.	285.958	0.327	0	0	0	0	0	0	0	1	0
1998	7	5.2	7349890	113	.	285.958	0.327	0	0	0	0	0	0	0	1	0
1998	8	1	1.7828E8	142602	1,250	294.925	0.000	0	0	0	0	0	0	0	1	0
1998	8	2	1.0382E8	24303	4,272	294.925	0.000	0	0	0	0	0	0	0	1	0
1998	8	3	2.5383E8	1657	,	294.925	0.000	0	0	0	0	0	0	0	1	0
1998	8	4	771181	473	,	294.925	0.000	0	0	0	0	0	0	0	1	0
1998	8	5.2	7151396	113	.	294.925	0.000	0	0	0	0	0	0	0	1	0
1998	9	1	1.737E8	142455	1,219	286.220	0.000	0	0	0	0	0	0	0	1	0
1998	9	2	1.0825E8	24368	4,442	286.220	0.000	0	0	0	0	0	0	0	1	0
1998	9	3	2.5122E8	1616	.	286.220	0.000	0	0	0	0	0	0	0	1	0
1998	9	4	843738	467	.	286.220	0.000	0	0	0	0	0	0	0	1	0
1998	9	5.2	6872418	113	.	286.220	0.000	0	0	0	0	0	0	0	1	0
1998	10	1	1.4186E8	142643	995	175.705	6.316	0	0	0	0	0	0	0	1	0
1998	10	2	95623330	24315	3,933	175.705	6.316	0	0	0	0	0	0	0	1	0
1998	10	3	2.5754E8	1651	.	175.705	6.316	0	0	0	0	0	0	0	1	0

1998	10	4	950987	523	.	175.705	6.316	0	0	0	0	0	0	0	1	0
1998	10	5.2	5174027	113	.	175.705	6.316	0	0	0	0	0	0	0	1	0
1998	11	1	1.5422E8	142896	1,079	12.959	127.598	0	0	0	0	0	0	0	1	0
1998	11	2	89644236	24496	3,660	12.959	127.598	0	0	0	0	0	0	0	1	0
1998	11	3	2.5853E8	1803	.	12.959	127.598	0	0	0	0	0	0	0	1	0
1998	11	4	1002788	536	.	12.959	127.598	0	0	0	0	0	0	0	1	0
1998	11	5.2	6360849	113	.	12.959	127.598	0	0	0	0	0	0	0	1	0
1998	12	1	2.0878E8	143048	1,460	2.749	244.364	0	0	0	0	-1	0	0	1	0
1998	12	2	1.0509E8	24450	4,298	2.749	244.364	0	3	0	0	-1	0	0	1	0
1998	12	3	3.0573E8	1659	.	2.749	244.364	0	0	0	0	-1	0	0	1	0
1998	12	4	1109403	525	.	2.749	244.364	0	0	0	0	-1	0	0	1	0
1998	12	5.2	8167601	113	.	2.749	244.364	0	0	0	0	-1	0	0	1	0
1999	1	1	2.8586E8	143197	1,996	1.178	619.041	0	0	0	0	0	0	0	1	0

YEAR	MONTH	revcls	KWH	CUST	USAGE	bcdd65	bhdd55	coml	com2	ind1	ind2	ind3	muni1	muni2	muni3	or1
1999	1	2	1.1745E8	24422	4,809	1.178	619.041	0	0	0	0	0	0	0	1	0
1999	I	3	2.7298E8	1668		1.178	619.041	0	0	0	0	0	0	0	1	0
1999	1	4	1091890	525		1.178	619.041	0	0	0	0	0	0	0	1	0
1999	1	5.2	8200469	113		1.178	619.041	0	0	0	0	0	0	0	1	0
1999	2	1	2.0991E8	143168	1,466	0.000	431.653	0	0	0	0	1	0	0	1	0
1999	2	2	99527085	24467	4,068	0.000	431.653	0	0	0	0	1	0	0	1	0
1999	2	3	2.24E8	1659		0.000	431.653	0	0	0	0	1	0	0	1	0
1999	2	4	936418	526		0.000	431.653	0	0	0	0	1	0	0	1	0
1999	2	5.2	7312958	113		0.000	431.653	0	0	0	0	1	0	0	1	0
1999	3	1	2.2364E8	143337	1,560	0.000	516.250	0	0	0	0	0	0	0	1	0
1999	3	2	1.0386E8	24536	4,233	0.000	516.250	0	0	0	0	0	0	0	1	0
1999	3	3	2.7508E8	1658		0.000	516.250	0	0	0	0	0	0	0	1	0
1999	3	4	931706	526		0.000	516.250	0	0	0	0	0	0	0	1	0
1999	3	5.2	7244392	113		0.000	516.250	0	0	0	0	0	0	0	1	0
1999	4	1	1.7521E8	143195	1,224	9.458	267.533	0	0	0	0	0	0	0	1	0
1999	4	2	94106931	24622	3,822	9.458	267.533	0	0	0	0	0	0	0	1	0
1999	4	3	2.6415E8	1648		9.458	267.533	0	0	0	0	0	0	0	1	0
1999	4	4	819222	527	.	9.458	267.533	0	0	0	0	0	0	0	1	0
1999	4	5.2	5426583	113		9.458	267.533	0	0	0	0	0	0	0	1	0
1999	5	I	1.2384E8	142917	867	32.071	32.300	0	0	0	0	0	0	0	1	0
1999	5	2	87169352	24638	3,538	32.071	32.300	0	0	0	0	0	0	0	1	0
1999	5	3	2.4614E8	1639		32.071	32.300	0	0	0	0	0	0	0	1	0
1999	5	4	742539	527		32.071	32.300	0	0	0	0	0	0	0	1	0

1999	5	5.2	5051934	113	.	32.071	32.300	0	0	0	0	0	0	0	1	0
1999	6	1	1.3974E8	142951	978	149.197	0.000	0	0	0	0	0	0	0	1	0
1999	6	2	97019424	24696	3,929	149.197	0.000	0	0	0	0	0	0	0	1	0
1999	6	3	2.5029E8	1637	.	149.197	0.000	0	0	0	0	0	0	0	1	0
1999	6	4	693125	529	.	149.197	0.000	0	0	0	0	0	0	0	1	0
1999	6	5.2	692892	113	.	149.197	0.000	0	0	0	0	0	0	0	1	0
1999	7	1	1.8124E8	142955	1,268	346.664	0.000	0	0	0	0	0	0	0	1	0
1999	7	2	1.098E8	24793	4,421	346.664	0.000	0	0	0	0	0	0	0	1	0
1999	7	3	2.4934E8	1634	.	346.664	0.000	0	0	0	0	0	0	0	1	0
1999	7	4	729393	532	.	346.664	0.000	0	0	0	0	0	0	0	1	0
1999	7	5.2	8031550	113	.	346.664	0.000	0	0	0	0	0	0	0	1	0
1999	8	1	1.9845E8	143050	1,387	430.050	0.000	0	0	0	0	0	0	0	1	0
1999	8	2	1.1182E8	24858	4,490	430.050	0.000	0	0	0	0	0	0	0	1	0
1999	8	3	2.5453E8	1628	.	430.050	0.000	0	0	0	0	0	0	0	1	0

YEAR	MONTH	revcls	KWH	COST	USAGE	bcdd65	bhdd55	com1	com2	ind1	ind2	ind3	muni1	muni2	muni3	or1
1999	8	4	799724	530		430.050	0.000	0	0	0	0	0	0	0	1	0
1999	8	5.2	7051167	113		430.050	0.000	0	0	0	0	0	0	0	1	0
1999	9	1	1.6124E8	143099	1, 7	219.067	0.131	0	0	0	0	0	0	0	1	0
1999	9	2	1.0098E8	24884	4, 8	219.067	0.131	0	0	0	0	0	0	0	1	0
1999	9	3	2.5705E8	1659	.	219.067	0.131	0	0	0	0	0	0	0	1	0
1999	9	4	849764	531	.	219.067	0.131	0	0	0	0	0	0	0	1	0
1999	9	5.2	6108505	113	.	219.067	0.131	0	0	0	0	0	0	0	1	0
1999	10	1	1.2901E8	143243	901	45.620	14.596	0	0	0	0	0	0	0	1	0
1999	10	2	95125923	25160	3,781	45.620	14.596	0	0	0	0	0	0	0	1	0
1999	10	3	2.3445E8	1637	.	45.620	14.596	0	0	0	0	0	0	0	1	0
1999	10	4	973333	532	.	45.620	14.596	0	0	0	0	0	0	0	1	0
1999	10	5.2	5190148	113	.	45.620	14.596	0	0	0	0	0	0	0	1	0
1999	11	1	1.5039E8	143398	1,049	2.553	121.740	0	0	0	0	0	0	0	1	0
1999	11	2	87415277	25140	3,477	2.553	121.740	0	0	0	0	0	0	0	1	0
1999	11	3	2.4769E8	1638	.	2.553	121.740	0	0	0	0	0	0	0	1	0
1999	11	4	1014483	531	.	2.553	121.740	0	0	0	0	0	0	0	1	0
1999	11	5.2	5729768	113	.	2.553	121.740	0	0	0	0	0	0	0	1	0
1999	12	1	2.1556E8	143574	[illegible]	0.000	297.576	0	0	0	0	0	0	0	1	0
1999	12	2	1.0659E8	25165	[illegible]	0.000	297.576	0	0	0	0	0	0	0	1	0
1999	12	3	2.8106E8	1630	.	0.000	297.576	0	0	0	0	0	0	0	1	0
1999	12	4	1110250	531	.	0.000	297.576	0	0	0	0	0	0	0	1	0
1999	12	5.2	8383775	113		0.000	297.576	0	0	0	0	0	0	0	1	0

2000	1	1	2.7658E8	143869	1,92[illegible]	0.000	539.714	0	0	1	0	0	0	0	1	0
2000	1	2	1.1605E8	25331	4,381	0.000	539.714	0	0	1	0	0	0	0	1	0
2000	1	3	1.956E8	1594	.	0.000	539.714	0	0	1	0	0	0	0	1	0
2000	1	4	1104283	533	.	0.000	539.714	0	0	1	0	0	0	0	1	0
2000	1	5.2	8185700	113	.	0.000	539.714	0	0	1	0	0	0	0	1	0
2000	2	1	2.7663E8	143934	1,922	0.000	715.255	0	0	-1	0	0	0	0	1	0
2000	2	2	1.1419E8	25282	4,317	0.000	715.255	0	0	-1	0	0	0	0	1	0
2000	2	3	3.3444E8	1538	.	0.000	715.255	0	0	-1	0	0	0	0	1	0
2000	2	4	938438	530	.	0.000	715.255	0	0	-1	0	0	0	0	1	0
2000	2	5.2	7546900	113	.	0.000	715.255	0	0	-1	0	0	0	0	1	0
2000	3	1	1.8931E8	143862	1,316	2.029	278.169	0	0	0	0	0	0	0	1	0
2000	3	2	97738698	25311	3,862	2.029	278.169	0	0	0	0	0	0	0	1	0
2000	3	3	2.6976E8	1534	.	2.029	278.169	0	0	0	0	0	0	0	1	0
2000	3	4	939037	530	.	2.029	278.169	0	0	0	0	0	0	0	1	0
2000	3	5.2	6119000	113	.	2.029	278.169	0	0	0	0	0	0	0	1	0

YEAR	MONTH	revcls	KWH	CUST	USAGE	bcdd65	bhdd55	com1	com2	ind1	ind2	ind3	muni1	muni2	muni3	or1
2000	4	1	1.5427E8	143461	1,075	4.713	153.615	0	0	0	0	0	0	0	1	0
2000	4	2	89933021	25327	3,551	4.713	153.615	0	0	0	0	0	0	0	1	0
2000	4	3	2.6491E8	1538	.	4.713	153.615	0	0	0	0	0	0	0	1	0
2000	4	4	817861	532	.	4.713	153.615	0	0	0	0	0	0	0	1	0
2000	4	5.2	5413800	113	.	4.713	153.615	0	0	0	0	0	0	0	1	0
2000	5	1	1.4315E8	143434	998	51.445	57.336	0	0	0	0	0	0	0	1	0
2000	5	2	92491053	25431	3,637	51.445	57.336	0	0	0	0	0	0	0	1	0
2000	5	3	2.5737E8	1524	.	51.445	57.336	0	0	0	0	0	0	0	1	0
2000	5	4	755515	531	.	51.445	57.336	0	0	0	0	0	0	0	1	0
2000	5	5.2	5392900	113	.	51.445	57.336	0	0	0	0	0	0	0	1	0
2000	6	1	1.502E8	143303	1,048	143.732	0.131	0	0	0	0	0	0	0	1	0
2000	6	2	1.0486E8	25460	4,118	143.732	0.131	0	0	0	0	0	0	0	1	0
2000	6	3	2.6148E8	1508	.	143.732	0.131	0	0	0	0	0	0	0	1	0
2000	6	4	705902	534	.	143.732	0.131	0	0	0	0	0	0	0	1	0
2000	6	5.2	6552800	113	.	143.732	0.131	0	0	0	0	0	0	0	1	0
2000	7	1	1.7495E8	143298	1,221	261.970	0.000	0	0	0	0	0	0	0	1	0
2000	7	2	1.0814E8	25553	4,232	261.970	0.000	0	0	0	0	0	0	0	1	0
2000	7	3	2.4959E8	1516	.	261.970	0.000	0	0	0	0	0	0	0	1	0
2000	7	4	744508	534	.	261.970	0.000	0	0	0	0	0	0	0	1	0
2000	7	5.2	6739700	113	.	261.970	0.000	0	0	0	0	0	0	0	1	0
2000	8	1	1.7011E8	143438	1,186	229.801	0.000	0	0	0	0	0	0	0	1	0

2000	8	2	1.0881E8	25605	4,250	229.801	0.000	0	0	0	0	0	0	0	1	0
2000	8	3	2.5144E8	1553	.	229.801	0.000	0	0	0	0	0	0	0	1	0
2000	8	4	803535	532	.	229.801	0.000	0	0	0	0	0	0	0	1	0
2000	8	5.2	6774700	113	.	229.801	0.000	0	0	0	0	0	0	0	1	0
2000	9	1	1.6462E8	143541	1,147	199.627	0.655	0	0	0	0	0	0	0	1	0
2000	9	2	1.1196E8	25597	4,374	199.627	0.655	0	0	0	0	0	0	0	1	0
2000	9	3	2.6409E8	1492	.	199.627	0.655	0	0	0	0	0	0	0	1	0
2000	9	4	890054	536	.	199.627	0.655	0	0	0	0	0	0	0	1	0
2000	9	5.2	5954700	113	.	199.627	0.655	0	0	0	0	0	0	0	1	0
2000	10	1	1.4094E8	143672	981	69.051	36.162	0	0	0	0	0	0	0	1	0
2000	10	2	96372646	25596	3,765	69.051	36.162	0	0	0	0	0	0	0	1	0
2000	10	3	2.5221E8	1523	.	69.051	36.162	0	0	0	0	0	0	0	1	0
2000	10	4	973790	532	.	69.051	36.162	0	0	0	0	0	0	0	1	0
2000	10	5.2	5468700	113	.	69.051	36.162	0	0	0	0	0	0	0	1	0
2000	11	1	1.4875E8	143791	1,035	9.589	124.064	0	0	0	0	0	0	0	1	0
2000	11	2	91910570	25750	3,569	9.589	124.064	0	0	0	0	0	0	0	1	0

YEAR	MONTH	revcls	KWH	CUST	USAGE	bcdd65	bhdd55	com1	com2	ind1	ind2	ind3	muni1	muni2	muni3	or1
2000	11	3	2.5563E8	1499	.	9.3557	124.064	0	0	0	0	0	0	0	1	0
2000	11	4	1029400	532	.	9.3557	124.064	0	0	0	0	0	0	0	1	0
2000	11	5.2	7041500	113	.	9.3557	124.064	0	0	0	0	0	0	0	1	0
2000	12	1	2.6572E8	144226	1,842	0.000	548.321	0	0	0	-1	0	0	0	1	0
2000	12	2	1.1696E8	25765	4,540	0.000	548.321	0	0	0	-1	0	0	0	1	0
2000	12	3	1.9155E8	1494	.	0.000	548.321	0	0	0	-1	0	0	0	1	0
2000	12	4	1129822	471	.	0.000	548.321	0	0	0	-1	0	0	0	1	0
2000	12	5.2	9607301	113	.	0.000	548.321	0	0	0	-1	0	0	0	1	0
2001	1	1	3.5221E8	144223	2,442	0.000	817.262	0	0	0	1	0	0	0	1	0
2001	1	2	1.3386E8	25718	5,205	0.000	817.262	0	0	0	1	0	0	0	1	0
2001	1	3	3.6373E8	1512	.	0.000	817.262	0	0	0	1	0	0	0	1	0
2001	1	4	1122283	471	.	0.000	817.262	0	0	0	1	0	0	0	1	0
2001	1	5.2	9197700	113	.	0.000	817.262	0	0	0	1	0	0	0	1	0
2001	2	1	2.618E8	144273	1,815	0.000	632.819	0	0	0	0	0	0	0	1	0
2001	2	2	1.135E8	25785	4,402	0.000	632.819	0	0	0	0	0	0	0	1	0
2001	2	3	2.5582E8	1503	.	0.000	632.819	0	0	0	0	0	0	0	1	0
2001	2	4	969514	446	.	0.000	632.819	0	0	0	0	0	0	0	1	0
2001	2	5.2	7119700	113	.	0.000	632.819	0	0	0	0	0	0	0	1	0
2001	3	1	2.1907E8	144119	1,520	0.000	442.977	0	0	0	0	0	0	0	1	0
2001	3	2	1.0278E8	25748	3,992	0.000	442.977	0	0	0	0	0	0	0	1	0

2001	3	3	2.6353E8	1498	.	0.0000	442.977	0	0	0	0	0	0	0	1	0
2001	3	4	961800	446	.	0.0000	442.977	0	0	0	0	0	0	0	1	0
2001	3	5 2	7494200	113	.	0.0000	442.977	0	0	0	0	0	0	0	1	0
2001	4	1	1.3078E8	143978	1,320	38.1583	304.023	0	0	0	0	0	0	0	1	0
2001	4	2	1.0019E8	25819	3,881	38.1583	304.023	0	0	0	0	0	0	0	1	0
2001	4	3	2.5158E8	1501	.	38.1583	304.023	0	0	0	0	0	0	0	1	0
2001	4	4	850414	445		38 1583	304 023	0	0	0	0	0	0	0	1	0
2001	4	5.2	5823600	113		38.1583	304.023	0	0	0	0	0	0	0	1	0
2001	5	1	1.4102E8	143932	980	85.0871	46.602	0	0	0	0	0	0	0	1	0
2001	5	2	97747035	25876	3,778	85.0871	46.602	0	0	0	0	0	0	0	1	0
2001	5	3	2.6211E8	1537	.	85.0871	46.602	0	0	0	0	0	0	0	1	0
2001	5	4	785878	446	.	85.0871	46.602	0	0	0	0	0	0	0	1	0
2001	5	5.2	5723400	113	.	85.0871	46.602	0	0	0	0	0	0	0	1	0
2001	6	1	1.4065E8	143849	978	91.3705	2.749	0	0	0	0	0	0	0	1	0
2001	6	2	1.0045E8	25911	3,877	91.3705	2.749	0	0	0	0	0	0	0	1	0
2001	6	3	2.6241E8	1536	.	91.3705	2.749	0	0	0	0	0	0	0	1	0
2001	6	4	735874	445	.	91.3705	2.749	0	0	0	0	0	0	0	1	0

YEAR	MONTH	revcls	KWH	CUST	USAGE	bcdd65	bhdd55	com1	com2	ind1	ind2	ind3	muni1	muni2	muni3	or1
2001	6	5.2	6241700	113	.	91.370	2.749	0	0	0	0	0	0	0	1	0
2001	7	1	1.7166E8	143853	1,193	227.444	0.000	0	0	0	0	0	0	0	1	0
2001	7	2	1.0976E8	25942	4,231	227.444	0.000	0	0	0	0	0	0	0	1	0
2001	7	3	2.5696E8	1521	.	227.444	0.000	0	0	0	0	0	0	0	1	0
2001	7	4	758156	446	.	227.444	0.000	0	0	0	0	0	0	0	1	0
2001	7	5 2	7179900	113	.	227.444	0.000	0	0	0	0	0	0	0	1	0
2001	8	1	1.8575E8	143911	1,291	331.316	0.000	0	0	0	0	0	0	0	1	0
2001	8	2	1.134E8	25971	4,366	331.316	0.000	0	0	0	0	0	0	0	1	0
2001	8	3	2.608E8	1522	.	331.316	0.000	0	0	0	0	0	0	0	1	0
2001	8	4	827130	445	.	331.316	0.000	0	0	0	0	0	0	0	1	0
2001	8	5 2	7400000	113	.	331.316	0.000	0	0	0	0	0	0	0	1	0
2001	9	1	1.7577E8	144012	1,221	257.650	0.131	0	0	0	0	0	0	0	1	0
2001	9	2	1.1374E8	26078	4,361	257.650	0.131	0	0	0	0	0	0	0	1	0
2001	9	3	2.4749E8	1519	.	257.650	0.131	0	0	0	0	0	0	0	1	0
2001	9	4	899978	444	.	257.650	0.131	0	0	0	0	0	0	0	1	0
2001	9	5 2	5633400	113	.	257.650	0.131	0	0	0	0	0	0	0	1	0
2001	10	1	1.4078E8	144138	977	63.063	27.195	0	0	0	0	0	0	0	1	0
2001	10	2	95920901	26151	3,668	63.063	27.195	0	0	0	0	0	0	0	1	0
2001	10	3	2.5902E8	1523	.	63.063	27.195	0	0	0	0	0	0	0	1	0

2001	10	4	1004158	444	.	63.063	27.195	0	0	0	0	0	0	0	1	0
2001	10	5.2	5707100	113	.	63.063	27.195	0	0	0	0	0	0	0	1	0
2001	11	1	1.6603E8	144214	1,151	18.654	131.296	0	0	0	0	0	0	0	1	0
2001	11	2	95928175	26236	3,656	18.654	131.296	0	0	0	0	0	0	0	1	0
2001	11	3	2.6531E8	1524	.	18.654	131.296	0	0	0	0	0	0	0	1	0
2001	11	4	1106597	444	.	18.654	131.296	0	0	0	0	0	0	0	1	0
2001	11	5.2	6966400	113	.	18.654	131.296	0	0	0	0	0	0	0	1	0
2001	12	1	2.0426E8	144447	1,414	0.589	170.567	0	0	0	0	0	0	0	1	0
2001	12	2	1.0478E8	26356	3,976	0.589	170.567	0	0	0	0	0	0	0	1	0
2001	12	3	2.6817E8	1510	.	0.589	170.567	0	0	0	0	0	0	0	1	0
2001	12	4	1171000	443		0.589	170.567	0	0	0	0	0	0	0	1	0
2001	12	5.2	4772400	113		0.589	170.567	0	0	0	0	0	0	0	1	0
2002	1	1	3.0015E8	144776	2,073	0.000	573.422	0	0	0	0	0	0	0	1	0
2002	1	2	1.2391E8	26454	4,684	0.000	573.422	0	0	0	0	0	0	0	1	0
2002	1	3	2.7829E8	1488	.	0.000	573.422	0	0	0	0	0	0	0	1	0
2002	1	4	1162628	441	.	0.000	573.422	0	0	0	0	0	0	0	1	0
2002	1	5.2	11766100	113	.	0.000	573.422	0	0	0	0	0	0	0	1	0
2002	2	1	2.4189E8	144635	1,672	0.000	472.888	0	0	0	0	0	0	0	1	0

YEAR	MONTH	revcls	KWH	CUST	USAGE	bcdd65	bhdd55	com1	com2	ind1	ind2	ind3	muni1	muni2	muni3	or1
2002	2	2	1.0802E8	26430	4,087	0.000	472.888	0	0	0	0	0	0	0	1	0
2002	2	3	2.6566E8	1509	.	0.000	472.888	0	0	0	0	0	0	0	1	0
2002	2	4	991174	438	.	0.000	472.888	0	0	0	0	0	0	0	1	0
2002	2	5.2	7496400	113	.	0.000	472.888	0	0	0	0	0	0	0	1	0
2002	3	1	2.3202E8	144570	1,[illegible]05	1.178	420.690	0	0	0	0	0	0	0	1	0
2002	3	2	1.0731E8	26967	3,[illegible]79	1.178	420.690	0	0	0	0	0	0	0	1	0
2002	3	3	2.6595E8	1520	.	1.178	420.690	0	0	0	0	0	0	0	1	0
2002	3	4	981060	439	.	1.178	420.690	0	0	0	0	0	0	0	1	0
2002	3	5.2	6729500	113	.	1.178	420.690	0	0	0	0	0	0	0	1	0
2002	4	1	1.8721E8	144471	1,[illegible]6	17.966	225.317	0	0	0	0	0	0	0	1	0
2002	4	2	1.0254E8	26499	3,[illegible]9	17.966	225.317	0	0	0	0	0	0	0	1	0
2002	4	3	2.7211E8	1500	.	17.966	225.317	0	0	0	0	0	0	0	1	0
2002	4	4	880087	439	.	17.966	225.317	0	0	0	0	0	0	0	1	0
2002	4	5.2	7866300	113	.	17.966	225.317	0	0	0	0	0	0	0	1	0
2002	5	1	.	.	.	42.630	63.113	0	0	0	0	0	0	0	1	0
2002	5	2	.	.	.	42.630	63.113	0	0	0	0	0	0	0	1	0
2002	5	3	.	.	.	42.630	63.113	0	0	0	0	0	0	0	1	0
2002	5	4	.		.	42.630	63.113	0	0	0	0	0	0	0	1	0

2002	5	5.2	.	.	.	42.630	63 113	0	0	0	0	0	0	0	1	0
2002	6	1	.	.	.	132.124	7.062	0	0	0	0	0	0	0	1	0
2002	6	2	.	.	.	132.124	7.062	0	0	0	0	0	0	0	1	0
2002	6	3	.	.	.	132.124	7.062	0	0	0	0	0	0	0	1	0
2002	6	4	.	.	.	132.124	7.062	0	0	0	0	0	0	0	1	0
2002	6	5.2	.	.	.	132.124	7.062	0	0	0	0	0	0	0	1	0
2002	7	1	.	.	.	275.389	0.089	0	0	0	0	0	0	0	1	0
2002	7	2	.	.	.	275.389	0.089	0	0	0	0	0	0	0	1	0
2002	7	3	.	.	.	275.389	0.089	0	0	0	0	0	0	0	1	0
2002	7	4	.	.	.	275.389	0.089	0	0	0	0	0	0	0	1	0
2002	7	5.2	.	.	.	275.389	0.089	0	0	0	0	0	0	0	1	0
2002	8	1	.	.	.	334.493	0.000	0	0	0	0	0	0	0	1	0
2002	8	2	.	.	.	334.493	0.000	0	0	0	0	0	0	0	1	0
2002	8	3	.		.	334.493	0.000	0	0	0	0	0	0	0	1	0
2002	8	4	.	.	.	334.493	0.000	0	0	0	0	0	0	0	1	0
2002	8	5.2	.	.	.	334.493	0.000	0	0	0	0	0	0	0	1	0
2002	9	1	.	.	.	258.766	0.260	0	0	0	0	0	0	0	1	0
2002	9	2	.	.	.	258.766	0.260	0	0	0	0	0	0	0	1	0
2002	9	3	.	.	.	258.766	0.260	0	0	0	0	0	0	0	1	0

YEAR	MONTH	revcls	KWH	CWST	USAGE	bcdd65	bhdd55	com1	com2	ind1	ind2	ind3	muni1	muni2	muni3	or1
2002	9	4	.	.	.	258.766	0.260	0	0	0	0	0	0	0	1	0
2002	9	5.2	.	.	.	258.766	0.260	0	0	0	0	0	0	0	1	0
2002	10	1	.	.	.	81.628	26.637	0	0	0	0	0	0	0	1	0
2002	10	2	.	.	.	81.628	26.637	0	0	0	0	0	0	0	1	0
2002	10	3	.	.	.	81.628	26.637	0	0	0	0	0	0	0	1	0
2002	10	4	.	.	.	81.628	26.637	0	0	0	0	0	0	0	1	0
2002	10	5.2	.	.	.	81.628	26.637	0	0	0	0	0	0	0	1	0
2002	11	1	.	.	.	11.458	147.282	0	0	0	0	0	0	0	1	0
2002	11	2	.	.	.	11.458	147.282	0	0	0	0	0	0	0	1	0
2002	11	3	.	.	.	11.458	147.282	0	0	0	0	0	0	0	1	0
2002	11	4	.	.	.	11.458	147.282	0	0	0	0	0	0	0	1	0
2002	11	5.2	.	.	.	11.458	147.282	0	0	0	0	0	0	0	1	0
2002	12	1	.	.	.	1.716	374.108	0	0	0	0	0	0	0	1	0
2002	12	2	.	.	.	1.716	374.108	0	0	0	0	0	0	0	1	0
2002	12	3	.	.	.	1.716	374.108	0	0	0	0	0	0	0	1	0
2002	12	4	.	.	.	1.716	374.108	0	0	0	0	0	0	0	1	0
2002	12	5.2	.	.	.	1.716	374.108	0	0	0	0	0	0	0	1	0

2003	1	1			.	5.541	595 745	0	0	0	0	0	0	0	1	0
2003	1	2	.	.	.	5.541	595.745	0	0	0	0	0	0	0	1	0
2003	1	3	.	.	.	5.541	595.745	0	0	0	0	0	0	0	1	0
2003	1	4	.	.	.	5.541	595.745	0	0	0	0	0	0	0	1	0
2003	1	5 2	.	.	.	5.541	595.745	0	0	0	0	0	0	0	1	0
2003	2	1	.	.	.	0.216	642.352	0	0	0	0	0	0	0	1	0
2003	2	2	.	.	.	0.216	642.352	0	0	0	0	0	0	0	1	0
2003	2	3	.	.	.	0.216	642.352	0	0	0	0	0	0	0	1	0
2003	2	4	.	.	.	0.216	642.352	0	0	0	0	0	0	0	1	0
2003	2	5 2	.	.	.	0.216	642.352	0	0	0	0	0	0	0	1	0
2003	3	1	.	.	.	2.022	454.409	0	0	0	0	0	0	0	1	0
2003	3	2	.	.	.	2.022	454.409	0	0	0	0	0	0	0	1	0
2003	3	3	.	.	.	2.022	454.409	0	0	0	0	0	0	0	1	0
2003	3	4	.	.	.	2.022	454.409	0	0	0	0	0	0	0	1	0
2003	3	5 2	.	.	.	2.022	454.409	0	0	0	0	0	0	0	1	0
2003	4	1	.	.	.	12.973	233.700	0	0	0	0	0	0	0	1	0
2003	4	2	.	.	.	12.973	233.700	0	0	0	0	0	0	0	1	0
2003	4	3	.	.	.	12.973	233.700	0	0	0	0	0	0	0	1	0
2003	4	4	.	.	.	12.973	233.700	0	0	0	0	0	0	0	1	0
2003	4	5 2	.	.	.	12.973	233.700	0	0	0	0	0	0	0	1	0

YEAR	MONTH	Nevcls	K2	CUST	USAGE	bodd65	bhCd55	com1	com2	imd1	inC2	ind3	Humi1	mumi2	Humi3	on1
2003	5	1	.	.	.	42.630	63▮ 13	0	0	0	0	0	0	0	1	0
2003	5	2	.	.	.	42.630	63.113	0	0	0	0	0	0	0	1	0
2003	5	3	.	.	.	42.630	63▮ 13	0	0	0	0	0	0	0	1	0
2003	5	4	.	.	.	42.630	63▮ 13	0	0	0	0	0	0	0	1	0
2003	5	5 2	.	.	.	42.630	63▮ 13	0	0	0	0	0	0	0	1	0
2003	6	1	.	.	.	132.124	7.062	0	0	0	0	0	0	0	1	0
2003	6	2	.	.	.	132.124	7.062	0	0	0	0	0	0	0	1	0
2003	6	3		.	.	132.124	7.062	0	0	0	0	0	0	0	1	0
2003	6	4		.	.	132.124	7.062	0	0	0	0	0	0	0	1	0
2003	6	5 2	.	.	.	132.124	7.062	0	0	0	0	0	0	0	1	0
2003	7	1	.	.	.	275.389	0.089	0	0	0	0	0	0	0	1	0
2003	7	2	.	.	.	275.389	0.089	0	0	0	0	0	0	0	1	0
2003	7	3	.	.	.	275.389	0.089	0	0	0	0	0	0	0	1	0
2003	7	4	.	.	.	275.389	0.089	0	0	0	0	0	0	0	1	0
2003	7	5 2		.	.	275.389	0.089	0	0	0	0	0	0	0	1	0
2003	8	1	.	.	.	334.493	0.000	0	0	0	0	0	0	0	1	0

2003	8	2			.	334.493	0.000	0	0	0	0	0	0	0	1	0
2003	8	3			.	334.493	0.000	0	0	0	0	0	0	0	1	0
2003	8	4			.	334.493	0.000	0	0	0	0	0	0	0	1	0
2003	8	5.2			.	334.493	0.000	0	0	0	0	0	0	0	1	0
2003	9	1			.	258.766	0.260	0	0	0	0	0	0	0	1	0
2003	9	2			.	258.766	0.260	0	0	0	0	0	0	0	1	0
2003	9	3			.	258.766	0.260	0	0	0	0	0	0	0	1	0
2003	9	4			.	258.766	0.260	0	0	0	0	0	0	0	1	0
2003	9	5.2			.	258.766	0.260	0	0	0	0	0	0	0	1	0
2003	10	1			.	81.628	26.637	0	0	0	0	0	0	0	1	0
2003	10	2			.	81.628	26.637	0	0	0	0	0	0	0	1	0
2003	10	3			.	81.628	26.637	0	0	0	0	0	0	0	1	0
2003	10	4			.	81.628	26.637	0	0	0	0	0	0	0	1	0
2003	10	5.2			.	81.628	26.637	0	0	0	0	0	0	0	1	0
2003	11	1			.	11.458	147.282	0	0	0	0	0	0	0	1	0
2003	11	2			.	11.458	147.282	0	0	0	0	0	0	0	1	0
2003	11	3			.	11.458	147.282	0	0	0	0	0	0	0	1	0
2003	11	4			.	11.458	147.282	0	0	0	0	0	0	0	1	0
2003	11	5.2			.	11.458	147.282	0	0	0	0	0	0	0	1	0
2003	12	1			.	1.716	374.108	0	0	0	0	0	0	0	1	0
2003	12	2			.	1.716	374.108	0	0	0	0	0	0	0	1	0

YEAR	MONTH	revcls	KWH	CUST	USAGE	bcdd65	bhdd55	com1	com2	ind1	ind2	ind3	muni1	muni2	muni3	or1
2003	12	3			.	1.71592	374.108	0	0	0	0	0	0	0	1	0
2003	12	4			.	1.71592	374.108	0	0	0	0	0	0	0	1	0
2003	12	5.2			.	1.71592	374.108	0	0	0	0	0	0	0	1	0